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Chapter 55
Oil and Gas Properties Production Tax

Article

Article 1
Gross Value at the Point of Production of Oil and Gas

Section

15 AAC 55.010. Monthly production rate at the economic limit for oil or gas produced before 1/1/95

Repealed.

History: Eff. 7/1/77, Register 63; am 3/26/82, Register 81; am 1/1/95, Register 132; repealed 5/3/2007, Register 182

15 AAC 55.011. Determination of applicable tax rate for oil and monthly production rate at the economic limit for oil or gas produced on or after 1/1/95

Repealed.

History: Eff. 1/1/95, Register 132; repealed 5/3/2007, Register 182

15 AAC 55.020. Well days for oil or gas produced before 1/1/95

Repealed.

History: Eff. 7/1/77, Register 63; am 2/23/88, Register 105; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.021. Days of well operation

(a) An operator of a lease or property from which oil or gas is produced during a month before January 1, 2012 shall, no later than the last day of the following month, submit to the department a detailed account of the individual well data showing the number of days and fractions of days that each well operated for the month. If the lease or property is within a unit participating area or includes a unit participating area, the well data must be reported for the unit participating area.

(b) Repealed 5/3/2007.

(c) A well is operating for purposes of this section when the well is yielding oil or gas that is considered to be produced under AS 43.55 and this chapter. An injection well, or a well yielding only gas that is not considered to be produced under 15 AAC 55.151(e) , is not operating within the meaning of this section.

(d) Repealed 5/3/2007.

(e) Repealed 5/3/2007.

(f) A hole drilled or bored in the ground to produce oil or gas, or both, is a single well, regardless of how many completions or lateral extensions that hole contains; how many pools, formations, or zones are produced through that hole; or whether that hole produces both oil and gas.

(g) Repealed 5/3/2007.

(h) Repealed 5/3/2007.

(i) Repealed 1/1/2000.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160; am 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.030

AS 43.55.110

AS 43.55.180

15 AAC 55.025. Computation of economic limit factor after 10 years of production for oil produced before January 1, 1989

Repealed.

History: Eff. 6/30/87, Register 103; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.027. Use of common production facilities between leases or properties

Repealed.

History: Eff. 1/1/95, Register 132; repealed 5/3/2007, Register 182

15 AAC 55.030. Economic limit factor for casinghead gas produced before 1/1/95

Repealed.

History: Eff. 7/1/77, Register 63; am 11/25/77, Register 64; am 3/26/82, Register 81; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.040. Interim taxation of gas well gas

Repealed.

History: Eff. 7/1/77, Register 63; repealed 1/1/95, Register 132

15 AAC 55.045. Economic limit factor for distillate or condensate produced before 1/1/95

Repealed.

History: Eff. 3/26/82, Register 81; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.050. Gas run through a gas processing plant

Repealed.

History: Eff. 7/1/77, Register 63; am 11/25/77, Register 64; am 1/1/2000, Register 152; repealed 5/3/2007, Register 182

15 AAC 55.052. Reasonable allowance for processing gas in a gas processing plant and for transporting gas from its point of production to a gas processing plant

Repealed.

History: Eff. 1/1/2000, Register 152; repealed 5/3/2007, Register 182

15 AAC 55.060. Lease identification number

Repealed.

History: Eff. 1/2/71, Register 36; am 1/1/95, Register 132; repealed 5/3/2007, Register 182

15 AAC 55.070. Penalty for gas flared before 1/1/95

Repealed.

History: Eff. 7/1/77, Register 63; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.071. Gas flared

Repealed.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2003, Register 164; repealed 5/3/2007, Register 182

15 AAC 55.080. Interest

Repealed.

History: Eff. 7/1/77, Register 63; am 1/1/95, Register 132; am 1/1/2000, Register 152; repealed 5/3/2007, Register 182

15 AAC 55.090. Significant digits in economic limit factors

Repealed.

History: Eff. 7/1/77, Register 63; am 11/25/77, Register 64; am 1/1/2002, Register 160; repealed 5/3/2007, Register 182

15 AAC 55.100. Average API gravity

Repealed.

History: Eff. 3/7/74, Register 49; am 6/28/74, Register 50; am 7/1/77, Register 63; repealed 5/3/2007, Register 182

15 AAC 55.110. Application of early development incentive credit against production tax

Repealed.

History: Eff. 12/24/75, Register 56; repealed 1/1/95, Register 132

15 AAC 55.115. Accounting for shrinkage when oil and NGLs are commingled

Repealed.

History: Eff. 1/1/2000, Register 152; repealed 5/3/2007, Register 182

15 AAC 55.120. Payment and reporting procedures

Repealed 9/15/82.

15 AAC 55.122. Supplemental submissions

Repealed.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; repealed 5/3/2007, Register 182

15 AAC 55.140. Processing cost deduction for a downstream gas plant

(a) For gas processed in a downstream gas plant under an arm's length contract, the processing cost deduction under 15 AAC 55.151(b) (2)(B) is the actual cost incurred by the producer under the contract for processing the taxable gas, except as otherwise provided under (c) of this section.

(b) For gas processed in a downstream gas plant other than under an arm's length contract, except as otherwise provided under (c) of this section, the processing cost deduction under 15 AAC 55.151(b) (2)(B)

(1) will be calculated by the department as a volume-weighted average of processing costs under arm's length contracts for comparable processing in the area where the downstream gas plant is located, if the department determines that sufficient arm's length contracts for comparable processing exist and are available to the department to provide a reliable basis for the processing cost deduction;

(2) otherwise is calculated using the methodology under 15 AAC 55.141.

(c) Allowable processing costs do not include

(1) a cost not directly related to processing of taxable gas;

(2) a cost for processing gas downstream of the point where destination value is determined under 15 AAC 55.151(b) (1);

(3) a cost greater than the consideration transferred, either directly or indirectly, from the producer to the processor, regardless of the cost or fee identified in a processing contract;

(4) a cost incidental to marketing.

(d) On or after January 1 of a calendar year during which a producer produces gas from leases or properties in the state that is processed in a downstream gas plant other than under an arm's length contract, the producer may request in writing the department's determination whether the processing cost deduction for the calendar year for that gas will be calculated under (b)(1) of this section or 15 AAC 55.141. No later than 90 days after receiving the request, the department will notify the producer of the department's determination. If the department determines that the processing cost deduction will be calculated under (b)(1) of this section, the department will provide the department's calculation to the producer no later than the later of July 1 of the calendar year or 150 days after the department receives the producer's request.

(e) If a producer's gas produced from leases or properties in the state is processed during a month in a downstream gas plant in an area where the producer's other gas is also processed during the month,

(1) for each downstream gas plant in that area in which the producer's gas from whatever source is processed, the percentage of the producer's gas processed in that plant during the month that is considered to be gas produced from leases or properties in the state is equal to the percentage that the producer's gas produced from leases or properties in the state constitutes of the producer's total amount of gas processed in downstream gas plants in that area during the month;

(2) if the producer has gas processed during the month under multiple contracts in a given downstream gas plant, the percentage of the producer's gas processed under each of those contracts during the month that is considered to be gas produced from leases or properties in the state is equal to the percentage that the producer's gas produced from leases or properties in the state constitutes of the producer's total amount of gas processed under those contracts during the month.

History: Eff. 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.900

15 AAC 55.141. Methodology for calculating certain gas processing cost deductions

(a) For gas processed in a downstream gas plant for which the processing cost deduction is calculated under this section, the applicable processing cost deduction is based on the downstream gas plant's actual and reasonable, directly allocable and attributable processing costs in the form of operating and maintenance expense, overhead, depreciation, and a return on undepreciated capital investment as provided in (c) of this section. Allowable capital costs are the original costs for depreciable fixed assets, including costs of delivery and installation of capital equipment that is an integral part of the plant.

(b) To compute depreciation for the purposes of this section, the producer shall use straight-line depreciation based on the economic life of the downstream gas plant. A change in ownership of a plant does not alter the depreciation schedule established by the original processor or producer for purposes of calculating a processing cost deduction under this section. Notwithstanding a change in ownership, a downstream gas plant may only be depreciated once. Equipment may not be depreciated below a reasonable, positive salvage value.

(c) Each February, the department will determine and publish the prevailing yield during the preceding January on corporate bonds whose relevant characteristics are comparable to those for which Moody's Investor Services, Inc., published its Moody's Seasoned Baa Corporate Bond Yield - All Industries for January 2010. The prevailing yield published by the department is the rate of return for purposes of calculating the return for that calendar year on undepreciated capital investment under (a) of this section.

(d) For a new downstream gas plant, the producer shall include in its initial processing cost deduction estimates of the directly allocable gas processing costs allowed under (a) of this section for the applicable period. The producer shall base cost estimates upon the most recently available operations data for the plant; if these data are not available, the producer shall base cost estimates upon industry data for similar downstream gas plants. To the extent a processing cost deduction is based on estimates, the deduction must be revised after actual costs are known.

(e) The billing determinant to be used in calculating a processing cost deduction under this section is throughput for the downstream gas plant.

(f) A reasonable share of overhead directly allocable and attributable to the operation and maintenance of a downstream gas plant is an allowable operating expense for purposes of this section.

(g) A producer may not include the following capital costs in determining a processing cost deduction under this section:

(1) a cost for a capital improvement or equipment that is not an integral part of the downstream processing plant;

(2) nondepreciable property, including land and a pipeline right-of-way;

(3) a facility used to store, deliver, or otherwise dispose of residue gas or gas plant products after extraction.

(h) A producer may not include the following non-capital costs in calculating a processing cost deduction under this section:

(1) operating and maintenance cost not directly related to processing;

(2) a cost associated with a capital improvement or equipment if the cost of the capital improvement or equipment is disallowed under (g) of this section;

(3) federal, state, or other income taxes;

(4) production or severance taxes;

(5) royalty payments.

History: Eff. 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.900

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15 AAC 55.150. Valuation of oil or gas produced before 1/1/95

Repealed.

History: Eff. 1/6/80, Register 73; am 5/21/81, Register 78; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.151. Gross value of oil or gas at the point of production

(a) Except as otherwise provided in 15 AAC 55.163, this section applies to all oil and gas produced in the state on a lease or property, regardless of whether the oil or gas is removed from the lease or property, less any oil or gas the ownership of or right to which is exempt from state taxation.

(b) The gross value at the point of production for a producer's oil or gas must be calculated as follows:

(1) a destination value must be determined for the oil or gas; the destination value is the sales price under 15 AAC 55.161 unless (c) or (d) of this section applies, in which case the destination value is the prevailing value under 15 AAC 55.171 or 15 AAC 55.173, as applicable;

(2) for oil and gas produced

(A) before July 1, 2007, the producer's reasonable costs of transportation under 15 AAC 55.180 and 15 AAC 55.191 must be subtracted from the destination value determined under (1) of this subsection; reasonable costs of transportation are calculated from the point of production of the oil or gas to its sales delivery point, or if different, to a point where prevailing value is calculated under 15 AAC 55.171 or 15 AAC 55.173;

(B) after June 30, 2007, the producer's costs of transportation under AS 43.55.150 and 15 AAC 55.193 and, if applicable, the producer's processing cost deduction under 15 AAC 55.140 or 15 AAC 55.141 must be subtracted from the destination value determined under (1) of this subsection; costs of transportation are calculated from the point of production of the oil or gas to its sales delivery point or, if the destination value determined under (1) of this subsection is the prevailing value, to the point where prevailing value is determined under 15 AAC 55.171 or 15 AAC 55.173;

(3) if oils of different qualities are commingled, the value calculated under (2) of this subsection must be adjusted for the cash value of the full consideration paid or received for quality differentials, regardless of whether prescribed by a filed tariff.

(4) if gas of different qualities is commingled, the value calculated under (2) of this subsection must be adjusted for the cash value of the full consideration paid or received for quality differentials, regardless of whether prescribed by a filed tariff, and including the value of any volumetric allocations or adjustments made on the basis of the relative BTU content, NGL content, or any other characteristic of the gas.

(c) The prevailing value under 15 AAC 55.171 or 15 AAC 55.173 must be used in determining the gross value at the point of production for a producer's oil or gas if

(1) the producer's oil or gas is refined, used as fuel or petrochemical feedstock, or otherwise consumed at a refinery or plant owned by the producer, or the oil or gas is transferred from the producer in other than an arm's length, third party transaction;

(2) the prevailing value for the producer's gas under 15 AAC 55.173, plus the total of the actual or reasonable costs of transportation, as applicable, incurred to transport the gas from the point where prevailing value is calculated to the sales delivery point and, if the gas has been processed in a downstream gas plant, the gas processing cost deduction under 15 AAC

55.140 or 15 AAC 55.141, exceed the sales price for that gas under 15 AAC 55.161, by more than one percent of the sales price; or

(3) the prevailing value for the producer's oil under 15 AAC 55.171, plus the actual or reasonable costs of transportation, as applicable, incurred to transport the oil from the point where prevailing value is calculated to the sales delivery point, exceed the sales price under 15 AAC 55.161 by more than $.15 per barrel.

(d) The department may apply prevailing value if the circumstances relating to the disposition of the producer's oil or gas show fraud or an intent to evade taxes.

(e) For purposes of AS 43.55 and this chapter, production of oil or gas does not include

(1) oil or gas used in production operations on a lease or property in the state by the producer;

(2) gas flared, released, or allowed to escape in amounts authorized by the Alaska Oil and Gas Conservation Commission;

(3) oil or gas injected by the producer into a reservoir on a lease or property in the state in the course of operations for purposes of repressuring, including enhanced recovery, but not including storage;

(4) oil or gas on which production tax has been previously paid;

(5) oil or gas sold or otherwise transferred by the producer to another producer of oil or gas in the state for use in a manner described in (1) or (3) of this subsection, if

(A) the producer of the oil or gas

(i) obtains an affidavit from the purchaser or transferee certifying under penalty of perjury that the oil or gas was used in the past year for a purpose described in (1) or (3) of this subsection; and

(ii) on March 31 of each year files with the department the affidavit obtained under (i) of this subparagraph together with the producer's statement described in AS 43.55.030 (a); and

(B) the oil or gas is actually used in a manner described in (1) or (3) of this subsection.

(f) Oil or gas deemed not to be produced under (e)(3) or (5) of this section is subject to tax on the basis of prevailing conditions at the time, and for the lease or property from which, the oil or gas is ultimately produced.

(g) If a producer transfers oil to a third party for purposes of operational necessity or convenience in what otherwise would be a bona fide, arm's-length exchange but for the fact that at the time of the particular transfer the producer expects to receive a like amount of similar quality oil produced in the state from that third party, the transfer to a third party and the transfer from the third party are disregarded and the oil is treated as if it had remained in the possession of the original transferring producer until final disposition of that oil. If the transfers under that exchange are made at different locations, the location differential paid by a producer is treated as a transportation cost and the location differential received by a producer is treated as a reimbursement of a transportation cost.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164; am 5/3/2007, Register 182; am 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

AS 43.55.150

AS 43.55.900

15 AAC 55.160. Sales price for oil or gas produced before 1/1/95

Repealed.

History: Eff. 1/6/80, Register 73; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.161. Sales price for oil or gas

(a) For purposes of this chapter, the sales price for oil or gas is the cash value of the full consideration being given in receipt for oil or gas transferred from a producer in an arm's length, third party transaction. For gas that has been processed in a downstream gas plant, the sales price is the total of the cash value of the full consideration being given in receipt for the residue gas and gas plant products transferred from a producer in an arm's length, third party transaction.

(b) Repealed 1/1/2000.

(c) In an exchange, the cash value for purposes of (a) of this section of the crude received in the exchange is

(1) the average spot price of the crude received that is published during the month that corresponds most closely to the pricing period identified in the contract for the crude received, if the crude received is priced by reference to a crude other than ANS and a pricing period is identified in the contract; or

(2) the average spot price of the crude received that is published during the month of delivery of the crude received, if the crude received is priced by reference to ANS or if a pricing period is not identified in the contract.

(d) If oil or gas is sold under a contract that contains a provision for reimbursing the producer for all or any part of the production taxes paid by the producer for that oil or gas, full consideration for purposes of (a) of this section includes the amount of the tax reimbursement received by the producer.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2003, Register 164; am 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

AS 43.55.150

15 AAC 55.163. Valuation of oil run through a North Slope field topping plant

(a) This section applies to oil run through a field topping plant in the Alaska North Slope area that is not returned and blended back into a production stream upstream of a point of production for oil.

(b) The gross value per barrel at the point of production for the oil is the prevailing value for that month determined under 15 AAC 55.171(g) multiplied by 1.2.

(c) The gross value determined under this section includes and is in place of the value of all pertinent cash receipts and disbursements between the owners of a field topping plant and the working interest owners of the oil run through the field topping plant.

History: Eff. 1/1/2003, Register 164

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.150

AS 43.55.190

15 AAC 55.165. Estimated payment of taxes based on market value for oil produced before 1/1/95

Repealed.

History: Eff. 9/1/84, Register 91; am 10/10/90, Register 116; am 2/14/91, Register 117; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.167. Transition rule for payment of estimated tax for third quarter 1990

Deleted.

History: Eff. 2/14/91, Register 117; deleted as of 1/2000, Register 152

Editor's note: As of Register 152 (January 2000), the regulations attorney deleted 15 AAC 55.167, a transitional provision, as obsolete.

15 AAC 55.170. Prevailing value for oil produced before 1/1/95

Repealed.

History: Eff. 1/6/80, Register 73; am 5/21/81, Register 78; am 9/1/84, Register 91; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.171. Prevailing value for oil

(a) The prevailing value for oil produced in the Alaska North Slope area ("ANS") and delivered to the United States West Coast, including Hawaii, is

(1) for oil transferred by the producer in an arm's-length, third party sale, the average spot price for ANS at the United States West Coast during the month that is referenced in the sales contract pricing provision; if more than one month is referenced in the sales contract pricing provision, the month with more daily spot price reports that fall within the contract price reference period must be used; in the case of an equal number of spot price reports, the month closer to the month of production must be used; if the sales contract has no price reference period, the prevailing value determined under (3) of this subsection must be used;

(2) for oil transferred by the producer in an arm's-length, third party exchange, the average spot price for ANS at the United States West Coast during the same month that is applied under 15 AAC 55.161(c) to the crude received in the exchange; if the department cannot determine the month in which the crude was received, the prevailing value determined under (3) of this subsection must be used; or

(3) for other oil, including oil that is refined, used as fuel or petrochemical feedstock, or otherwise consumed at a refinery or plant owned by the producer, the average spot price for ANS at the United States West Coast during the month of delivery of that oil.

(b) Repealed 1/1/2000.

(c) Repealed 1/1/2000.

(d) Repealed 1/1/2000.

(e) Repealed 1/1/2000.

(f) The prevailing value for ANS sold in the state at tidewater or delivered to coastal refineries in the state is the prevailing value determined in (a) of this section minus the volume-weighted average location differential between the Port of Valdez and the United States West Coast provided for under contracts for the sale of ANS delivered in the state during the previous calendar year. The department will calculate the annual volume-weighted average location differential by analyzing contracts entered into during the 18-month period ending November 30 of the previous calendar year for the sale of producers' ANS delivered in the state. The department will use contracts that it has received from producers by January 15 of the current calendar year. The department will calculate the location differential and the number of barrels specified to be delivered under each contract. The differential for each contract will be multiplied by the total number of barrels specified to be delivered under that contract. The resulting totals for all contracts will be added together, and that sum will be divided by the total number of barrels delivered under all of the contracts. If two or fewer contracts are entered into during the 18-month period ending

November 30 of the previous calendar year that meet the criteria in this subsection, the department will use the volume-weighted average of marine transportation costs, reported monthly under AS 43.55.030 (f)(2), during the prior 12-month period ending June 30 of the previous calendar year, less 25 percent of those reported marine transportation costs. The resulting location differential is a per-barrel amount. The department will provide notice to the producers of the amount of the location differential no later than February 10 each year.

(g) The prevailing value for ANS sold at Trans Alaska Pipeline System ("TAPS") pump station number one or sold at the entrance to a publicly regulated pipeline other than TAPS is the prevailing value determined in (f) of this section minus the carrier ownership-weighted average of all applicable publicly filed pipeline tariffs and the quality bank differentials, not including the TAPS Valdez Marine Terminal Quality Bank, for oil produced from the relevant lease or property and transported between the location of sale and the TAPS terminal in Valdez. If a carrier has more than one applicable publicly filed pipeline tariff, the lowest tariff filed by that carrier must be used in calculating the carrier ownership-weighted average.

(h) The prevailing value for ANS delivered to an inland refinery in the state is the prevailing value as determined in (f) of this section, minus the carrier ownership-weighted average of all applicable TAPS tariffs and the quality bank differentials, not including the TAPS Valdez Marine Terminal Quality Bank, for oil transported between TAPS pump station number one and the TAPS terminal in Valdez, plus the carrier ownership-weighted average of all applicable publicly filed pipeline tariffs and the per-barrel quality bank adjustments for oil transported between TAPS pump station number one and the refinery. If a carrier has more than one applicable publicly filed pipeline tariff, the lowest tariff filed by that carrier must be used in calculating the carrier ownership-weighted average.

(i) Repealed 1/1/2004.

(j) Repealed 1/1/2004.

(k) The prevailing value for oil produced in the state and delivered to a location other than those specified in (a) or (f) - (j) of this section is the value of comparable crudes delivered to the same regional market, as adjusted for quality and location and measured by indices of current market value.

(*l*) Repealed 1/1/2000.

(m) For purposes of this section, the average spot price for ANS at the United States West Coast during a month is the average of the monthly average assessments for the month by *Platt's Oilgram Price Report*, Dow Jones Energy Service, and Reuters online data providing service, calculated to three decimal places using the automatic convention in the rounding command or function in commercially available software. If *Platt's Oilgram Price Report*, Dow Jones Energy Service, or Reuters online data providing service ceases to report daily assessments for ANS at the United States West Coast, the average spot price for ANS at the United States West Coast is the average of the monthly average assessments by all remaining reporting services. In this subsection, a monthly average assessment for a month is the average of the midpoints between a reporting service's high and low closing assessments for ANS at the United States West Coast for all days during the month for which closing assessments are reported.

(n) Repealed 1/1/2000.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 11/1/2000, Register 156; am 1/1/2002, Register 160; am 1/1/2003, Register 164; am 1/1/2004, Register 168; am 5/3/2007, Register 182; am 4/30/2010, Register 194; am 6/4/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

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15 AAC 55.172. Prevailing value for gas produced before 1/1/95

Repealed.

History: Eff. 5/21/81, Register 78; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.173. Prevailing value for gas

(a) For gas delivered in the Alaska North Slope area, the prevailing value is,

(1) for each Mcf of gas produced before October 1, 2008, 10 percent of the prevailing value per barrel that would be determined under 15 AAC 55.171(g) for oil that is produced from the lease or property from which the gas is produced and that is sold at the entrance to the regulated oil pipeline serving that lease or property; if during the month that the gas is delivered oil is not produced from that lease or property and delivered into a regulated oil pipeline serving that lease or property, the prevailing value calculation must be made with respect to the nearest lease or property from which oil is produced and delivered that month into a regulated oil pipeline;

(2) for gas produced on or after October 1, 2008 and before the commencement of commercial operation of a regulated pipeline facility that delivers gas outside of the Alaska North Slope area, the weighted average sales price of sales from producers of gas to regulated utilities in the Alaska North Slope area for the three-month period ending one month before the end of the previous calendar quarter; in the absence of sales from producers to regulated utilities in the Alaska North Slope area, the department will determine the prevailing value on another reasonable basis under AS 43.55.020 (f); the department will publish on the 15th day of each calendar quarter the prevailing value for that quarter;

(3) for gas produced after the commencement of commercial operation of a regulated pipeline facility that delivers gas outside of the Alaska North Slope area, the prevailing value determined under (j) of this section, adjusted for differences, if any, in location, quality, or composition between unprocessed gas delivered into the pipeline facility and gas delivered in the Alaska North Slope area.

(b) For gas delivered in the Cook Inlet area during a calendar quarter, the prevailing value is the weighted average price of significant sales of gas from producers of gas to publicly regulated utilities in the Cook Inlet area for the three month period ending one month before the end of the previous calendar quarter. The department will publish on the 15th day of each calendar quarter the prevailing value for that quarter. For purposes of this subsection, "significant sales" means sales of 10,000 Mcf per month or more.

(c) For gas delivered by pipeline to a market in Canada or the Lower 48, the prevailing value for the month of production of that gas is determined as follows:

(1) except as provided in (3) of this subsection, for unprocessed gas delivered in, or downstream of, a first destination market with reasonable liquidity, the prevailing value is the total value of the component residue gas and component gas plant products, based on market price indices for residue gas and gas plant products determined by the department under (n) of this section, as adjusted for quality or location, for the first destination market with reasonable liquidity, after deduction of a downstream gas processing cost allowance;

(2) except as provided in (3) of this subsection, if gas has been processed in a downstream gas plant and delivered in, or downstream of, a first destination market with reasonable liquidity, the prevailing value is the total value of the residue gas and the gas plant products, based on market price indices for residue gas and gas plant products determined by the department under (n) of this section, for the first destination market with reasonable liquidity, after deduction of a downstream gas processing cost allowance;

(3) if unprocessed gas, residue gas, or gas plant products are not delivered in, or downstream of, a first destination market with reasonable liquidity and are not subject to (k) of this section, or if the department determines that a methodology set out in (1) and (2) of this subsection cannot practicably be applied, the department will determine the prevailing value using one of the following methods:

(A) the weighted average sales price of all gas produced in the state and sold in arm's length, third party transactions in the month of delivery in the same destination market;

(B) the weighted average sales price of all gas produced in the state and sold in arm's length, third party transactions in the month of delivery in the same regional market;

(C) the value of comparable gas delivered to the same regional market, as adjusted for quality and location and based on applicable reference prices published by government entities in Canada or the United States, or any other source of market price information identified by the department as reasonably reliable for purposes of determining the value of the gas.

(d) For gas delivered in the United States outside the state or in a foreign market by means of an LNG transportation facility, the prevailing value for the month of production of that gas is determined as follows:

(1) except as provided in (2) of this subsection, for LNG delivered in or downstream of a first destination market with reasonable liquidity, prevailing value is the higher of

(A) the total value of the LNG based on the market price index determined by the department under (n) of this section for LNG of like kind, quality, and condition for that market;

(B) the total value of the LNG based on the market price index determined by the department under (n) of this section for regasified LNG or the market price indices determined by the department under (n) of this section for residue gas and gas plant products, after deduction of a regasification cost allowance and, if applicable, a downstream gas processing cost allowance, and after applying any location or quality differentials determined by the department;

(2) if the LNG or regasified LNG is not delivered in, or downstream of, a first destination market with reasonable liquidity, or if the department determines that the methodology set out in (1) of this subsection cannot practicably be applied, the department will determine the prevailing value using one of the following methods:

(A) the weighted average sales price of all gas produced in the state and sold in arm's length, third party transactions in the month of delivery in the same destination market.

(B) the weighted average sales price of all gas produced in the state and sold in arm's length, third party transactions in the month of delivery in the same regional market;

(C) the value of comparable gas delivered to the same regional market, as adjusted for quality and location, based on applicable reference prices published by government entities in the foreign market or the United States, or any other source of market price information identified by the department as reasonably reliable for purposes of determining the value of LNG, regasified LNG, residue gas, or gas plant products for that same regional market.

(e) Repealed 5/3/2007.

(f) Repealed 5/3/2007.

(g) A producer that sells gas that has been produced from a lease or property in the state shall, as part of its monthly report under AS 43.55.030 (f), file with the department a copy of the sales invoice for each sales transaction for the month covered by the report and a copy of any contract to sell gas produced from a lease or property in the state that the producer entered into during the month covered by the report.

(h) Repealed 1/1/2000.

(i) Notwithstanding (a)(2) of this section, for the July - September 2008 calendar quarter, the department will publish within 15 days after October 1, 2008 the prevailing value for that quarter for gas delivered in the Alaska North Slope area.

(j) For gas sold at the inlet to a gas treatment plant or at the inlet to a regulated gas pipeline facility capable of transporting gas to areas of the state outside of the Alaska North Slope area, the prevailing value for the month of production of that gas is the prevailing value determined in (c) of this section for the first destination market with reasonable liquidity for residue gas and gas plant products, or if there is more than one first destination market with reasonable liquidity, the weighted average of the prevailing values determined under (c) of this section, minus the volume-weighted average of all applicable filed pipeline tariff rates for gas produced from the lease or property and transported to the destination market and, if applicable, minus the cost of gas treatment at the gas treatment plant. In calculating a volume-weighted average of pipeline tariff rates under this subsection, the department may use data from an appropriate prior tax period as necessary to allow for a more contemporaneous determination of prevailing value. For purposes of this subsection, the cost of gas treatment is

(1) if the gas treatment plant is regulated, the applicable tariff rate for the gas treatment plant or, if there is more than one applicable filed tariff rate, the weighted average of all of those rates;

(2) if the gas treatment plant is not regulated, the cost determined by the department using the methodology under 15 AAC 55.197 for current or prior tax periods.

(k) For North Slope gas delivered at an offtake point or other point downstream from the inlet to a regulated gas pipeline facility in an area of the state outside of the Alaska North Slope area or in Canada or the Lower 48 but upstream from a first destination market with reasonable liquidity, the prevailing value for the month of production of that gas is the prevailing value determined in (c) of this section for the first destination market with reasonable liquidity for residue gas and gas plant products, or if there is more than one first destination market with reasonable liquidity, the weighted average of the prevailing values determined under (c) of this section, minus the volume-weighted average of all applicable filed pipeline tariff rates for gas transported from that offtake or other point to the first destination market. In calculating a volume-weighted average of pipeline tariff rates under this subsection, the department may use data from an appropriate prior tax period as necessary to allow for a more contemporaneous determination of prevailing value.

(*l*) For North Slope gas delivered to and sold at the inlet to the liquefaction plant of an LNG transportation facility located in or near Valdez, Alaska, by use of a pipeline facility that does not also deliver gas to Canada or the Lower 48, the prevailing value is the prevailing value determined by the department in (d) of this section for LNG deliveries to the destination market or if there is more than one destination market, the weighted average of the prevailing values determined under (d) of this section, minus the volume-weighted average costs of transportation, determined under 15 AAC 55.193, between the inlet of the liquefaction facility and the destination markets. In calculating a volume-weighted average cost of transportation under this subsection, the department may use data from an appropriate prior tax period as necessary to allow for a more contemporaneous determination of prevailing value.

(m) For gas delivered by pipeline to any location outside of the Alaska North Slope area other than those locations provided for in (c), (d), (k), and (*l*) of this section, the prevailing value of the gas is the higher of

(1) the prevailing value determined under (k) of this section at the applicable offtake point from the pipeline facility originating in the Alaska North Slope area, plus the volume-weighted average of all applicable filed pipeline tariff rates, if any, between the offtake point and the sales delivery point; or

(2) the weighted average sales price of all gas produced in the state and sold in arm's length, third party transactions in the month of delivery in the same regional market.

(n) For purposes of determining prevailing value under this section,

(1) a first destination market with reasonable liquidity is a destination market that the department determines satisfies the following criteria:

(A) for residue gas,

(i) the average daily volume of residue gas sold in arm's length transactions exceeds 100,000 MMBTUs; and

(ii) there is sufficient market price information reasonably available in that market for the department to establish a market price index under (2) of this subsection and, if applicable, an adjustment under (3) of this subsection for residue gas for that market;

(B) for LNG,

(i) the average daily volume of LNG or regasified LNG sold in arm's length transactions is substantial; and

(ii) there is sufficient market price information reasonably available in that market for the department to establish a market price index under (2) of this subsection and, if applicable, an adjustment under (3) of this subsection for LNG for that market;

(C) for gas plant products,

(i) gas plant products are either extracted or fractionated in the market for purposes of sale;

(ii) the market is designated as a first destination market for residue gas under (A) of this paragraph; and

(iii) there is sufficient market price information reasonably available either in that destination market or in another market for gas plant products connected by pipeline to that destination market for the department to establish a market price index under (2) of this subsection and, if applicable, an adjustment under (3) of this subsection for gas plant products for that market;

(2) for residue gas, LNG, or gas plant products, the department will determine a market price index, if appropriate, based on information published on a regular basis in reliable and widely available industry trade publications, applicable reference prices published by government entities in Canada or the United States, or any other source of market price information identified by the department as reasonably reliable for purposes of determining a value of residue gas, LNG, or gas plant products for that location or area, as adjusted for quality and location differentials and if applicable, any adjustment under (3) of this subsection;

(3) for residue gas, LNG, or gas plant products, the department may determine an appropriate adjustment between component residue gas and component gas plant products, and among actual or potential component gas plant products, based on BTU content, NGL content, or any other characteristic of the producer's gas that is required to determine a prevailing value under this section.

(o) The department will determine a reasonable downstream gas processing cost allowance, or in the case of LNG, a reasonable regasification cost allowance to be used in the calculation of prevailing value under this section, using one of the following methods as applicable:

(1) downstream gas processing costs or regasification costs published by an industry trade journal, a governmental entity, or any other reliable source of this information, adjusted for quality, location, and any service charges embedded in the published cost and not directly related to processing or regasification; for purposes of this paragraph, service charges include marketing allowances;

(2) for a gas processing cost allowance, a weighted average of downstream gas processing cost deductions determined by the department under 15 AAC 55.140(b) (2) and 15 AAC 55.141, for current or prior tax periods, as adjusted for quality or location;

(3) for a regasification cost allowance, a weighted average of actual transportation costs for regasification facilities determined under 15 AAC 55.193(b) (4)(B) and 15 AAC 55.196 for current or prior tax periods, as adjusted for quality or location;

(4) a weighted average of arm's length downstream gas processing costs or regasification costs for current or prior tax periods, as adjusted for quality or location.

(p) In this section,

(1) "Alaska North Slope area" means that part of the state that lies north of 68 degrees North latitude;

(2) "offtake point" means a point of delivery along the length of a long-distance integrated pipeline facility that is capable of providing connections to other lateral pipelines for delivery to markets separate from the mainline or to local gas distribution lines for residential or commercial use, or to both;

(3) "unprocessed gas" means gas that has not been subject to downstream gas processing.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2003, Register 164; am 5/3/2007, Register 182; am 10/1/2008, Register 187; am 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

15 AAC 55.175. Allocation of value between oil and NGLs

Repealed.

History: Eff. 1/1/2000, Register 152; am 1/1/2003, Register 164; repealed 5/3/2007, Register 182

Publisher's note: This section appears in Register 185 to make a correction in the history as it appears in the main pamphlet.

15 AAC 55.177. Publication of information related to prevailing value determinations for gas

(a) For purposes of determining the prevailing value for gas under 15 AAC 55.173, the department will publish the information described in (b) of this section as follows:

(1) for the period that (A) begins with the date of commencement of commercial operation of a regulated pipeline that delivers gas to Canada, to the Lower 48, or to an LNG transportation facility located in or near Valdez, Alaska; and (B) ends on the last day of the same tax year, the department will publish the information at least 60 days before the date of commencement of commercial operation;

(2) for each tax year later than the tax year described in (1) of this subsection, the department will publish the information on or before December 1 of the immediately preceding year.

(b) The information to be published by the department under (a) of this section is

(1) the identification of each market that the department has determined to be a first destination market with reasonable liquidity for residue gas, for gas plant products, or for LNG;

(2) for each first destination market with reasonable liquidity,

(A) the name of the publication or other source of the market price index for residue gas, for gas plant products, or for LNG;

(B) a description of the specific price information that can be referenced; and

(C) the manner in which that price information must be applied, including a description of any location or quality differential that the department determines to be appropriate to adjust the market price index in a given market;

(3) the method the department has selected to determine a downstream gas processing cost allowance or a regasification cost allowance under15 AAC 55.173(o) for each first destination market with reasonable liquidity;

(4) to the extent practicable, the destination markets and the alternative prevailing value methods the department may apply under15 AAC 55.173(c)(3) and (d)(2) in those markets; and

(5) to the extent practicable, any other information relating to the determination of prevailing value under15 AAC 55.173.

(c) To the extent practicable, for each first destination market with reasonable liquidity identified by the department under (b) of this section, the department will publish on a monthly or other periodic basis the market price index determined by the department under15 AAC 55.173(n), and any other information the department has determined can be reasonably provided related to the calculation of prevailing value for gas under15 AAC 55.173.

(d) In this section, "Alaska North Slope area" means that part of the state that lies north of 68 degrees North latitude.

History: Eff. 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

15 AAC 55.180. Choice of methods for determining reasonable cost of transportation for oil and gas produced before July 1, 2007

(a) Except as provided in (b) of this section, the reasonable cost of transportation is the actual cost of transportation as determined in 15 AAC 55.191(a) and (b), if the actual costs incurred are ordinary and necessary transportation expenses.

(b) The reasonable cost of transportation is the fair market value as defined in 15 AAC 55.191(h) if all of the following conditions exist:

(1) the parties to the transportation of oil or gas are affiliated;

(2) the contract for the transportation of oil or gas is not an arm's-length transaction or is not representative of the market value of the transportation; and

(3) the method of transportation of oil or gas is not reasonable in view of existing alternative methods of transportation.

(c) This section applies to oil and gas produced before July 1, 2007.

History: Eff. 1/6/80, Register 73; am 1/1/95, Register 132; am 1/1/2000, Register 152; am 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

AS 43.55.150

15 AAC 55.181. Comparison of actual and reasonable costs of transportation for oil and gas produced after June 30, 2007

(a) Except as otherwise provided under (b) of this section, for purposes of determining the lower of actual costs of transportation or reasonable costs of transportation under AS 43.55.150 (b), if the department finds under AS 43.55.150 (b) that a condition in

(1) AS 43.55.150 (a)(1) or (2) is present, the actual costs of transporting the producer's oil or gas from the point where the oil or gas is tendered into the transportation facility to the point where the oil or gas is delivered from the facility are compared to the reasonable costs of transporting the producer's oil or gas from the point where the oil or gas is tendered into the transportation facility to the point where the oil or gas is delivered from the facility;

(2) AS 43.55.150 (a)(3) is present, the actual costs of transporting the producer's oil or gas by the method or under the terms the department finds to be not reasonable are compared to the reasonable costs of transporting the producer's oil or gas for that portion of the transportation of the oil or gas as to which the department finds the method or terms of the actual transportation used are not reasonable.

(b) If different filed tariff rates for intrastate transportation and for interstate transportation apply to the transportation of oil or gas from a given point where that oil or gas is tendered into a regulated transportation facility to a given point where it is delivered from the facility, the comparison of actual costs of transportation and reasonable costs of transportation under (a) of this section is made separately for the intrastate transportation and the interstate transportation of the oil or gas.

(c) For purposes of determining the lower of actual costs of transportation or reasonable costs of transportation under AS 43.55.150 (b) in the case of transportation for which actual costs of transportation are determined under 15 AAC 55.193(b) (1) or (5), if the tariff rate has a materially different rate structure or capital recovery profile than the reasonable costs of transportation determined under 15 AAC 55.193(c) (5), the department may allow or require the comparison of actual costs and reasonable costs to be made using comparable rate structures and capital recovery profiles.

(d) For purposes of AS 43.55.150 and this section, a physical pipeline is a single transportation facility regardless of whether multiple carriers own interests in the pipeline, file separate tariffs for transporting oil or gas in the pipeline, or enter into separate contracts with shippers to transport oil or gas in the pipeline.

(e) On or after January 1 of a calendar year during which a producer expects to produce oil or gas for which the producer may be required under AS 43.55.150 (b) to calculate the gross value at the point of production of oil or gas using the lower of the actual costs of transportation or the reasonable costs of transportation of the oil or gas, if the reasonable costs of transportation are determined under 15 AAC 55.193(c) (5) or (e) - (j), the producer may request in writing the department's determination of the reasonable costs of transportation. The department will provide the department's determination to the producer no later than the later of July 1 of the calendar year or 180 days after the department receives the producer's request. Regardless of whether the department receives a request under this subsection, the department may at any time determine the reasonable costs of transportation of oil or gas under AS 43.55.150 (b).

(f) This section applies to oil and gas produced after June 30, 2007.

History: Eff. 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

AS 43.55.150

15 AAC 55.190. Calculation of reasonable costs of transportation for oil or gas produced before 1/1/95

Repealed.

History: Eff. 1/6/80, Register 73; am 5/21/81, Register 78; am 1/1/95, Register 132; repealed 1/1/2000, Register 152

15 AAC 55.191. Calculation of reasonable costs of transportation for oil or gas produced before July 1, 2007

(a) Reasonable costs of transportation are the ordinary and necessary costs incurred to transport the oil or gas from the point of production to the sales delivery point or, if gas produced before April 1, 2006 has been run through a gas processing plant, from the plant to the sales delivery point.

(b) Actual costs of transportation allowable for purposes of 15 AAC 55.180(a) are

(1) if transportation of oil or gas is by a regulated carrier, the tariff that is on file with the Federal Energy Regulatory Commission or other regulatory agency having jurisdiction, and that is applicable to that transportation of the oil or gas by the carrier, from the point where that oil or gas is tendered into the facilities of the carrier to the point where it is delivered from the facilities of the carrier;

(2) if transportation of oil is by a vessel that is not owned or effectively owned, in whole or in part, by the producer of that oil

(A) for a single voyage charter, the total costs under the charter for that vessel, plus any voyage and port costs as provided in (j) of this section if those voyage and port costs are incurred for that transportation during the term of the charter, are not included in the charter fee, and are borne by the producer, plus the positioning costs, if any, borne by the producer for that vessel;

(B) for a consecutive voyage charter or a time charter, the total costs under the charter for that vessel, plus any voyage and port costs as provided in (j) of this section if those voyage and port costs are incurred for that transportation during the term of the charter, are not included in the charter fee, and are borne by the producer, plus the positioning cost, if any, borne by the producer for that vessel; the positioning cost must be amortized over the lesser of 36 months or the term of the charter in the case of a time charter, and amortized on the basis of the number of voyages in the case of a consecutive voyage charter; or

(C) for a contract of affreightment, the total costs under the contract, plus any voyage and port costs as provided in (j) of this section if those voyage and port costs are incurred for that transportation during the contract of affreightment, are not included in the charter fee, and are borne by the producer, plus any positioning costs not included in that fee that are incurred with respect to that transportation during the contract of affreightment and that are borne by the producer;

(3) if transportation of oil is by a vessel that is owned or effectively owned, in whole or in part, by the producer of that oil, the producer's actual cost for that transportation, which is the sum of

(A) voyage and port costs incurred with respect to that transportation, as provided in (j) of this section;

(B) the positioning cost, amortized over 36 months, for that vessel;

(C) depreciation of the vessel as calculated by the producer for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or as provided in 15 AAC 55.195(a) , (b), (c), (f), or (h) or 15 AAC 55.196, as applicable; and

(D) an amount that, when added to the amount of depreciation allowed under (C) of this paragraph, will provide a reasonable return on the acquisition cost, as provided in 15 AAC 55.195(a) , of the vessel over its expected useful life as used for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or on the adjusted shipyard cost or invested capital as provided in 15 AAC 55.195(b) , (c), (f), or (h) or 15 AAC 55.196, as applicable;

(4) in the case of transportation of gas as liquefied natural gas (LNG),

(A) if not all of the LNG transportation facilities are subject to tariff regulations of the Federal Energy Regulatory Commission or another federal agency, a state, territory, or possession of the United States, or a foreign nation, and if the producer does not own or effectively own, in whole or in part, the LNG transportation facility, the amount charged to the producer for that LNG transportation;

(B) if the producer owns or effectively owns, in whole or in part, the LNG transportation facility, the producer's actual cost for that transportation, which is the sum of

(i) the direct operating costs of the LNG transportation facility incurred with respect to the producer's gas; for an LNG tanker, direct operating costs consist of the tanker's voyage and port costs as provided in (j) of this section;

(ii) the positioning cost, amortized over 36 months, in the case of an LNG tanker;

(iii) depreciation of the LNG transportation facility as calculated by the producer for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or as provided in 15 AAC 55.195(a) , (b), (c), or (d), as applicable;

(iv) an amount that, when added to the amount of depreciation allowed under (iii) of this subparagraph, will provide a reasonable return on the acquisition cost, as provided in 15 AAC 55.195(a) , (b), (c), or (d), as applicable, of the LNG transportation facility over its expected useful life as used for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or on the adjusted shipyard cost as provided in 15 AAC 55.195(a) , (b), (c), or (d), as applicable;

(5) if transportation of oil or gas is by a nonregulated pipeline facility that is not owned or effectively owned, in whole or in part, by the producer of that oil or gas, the transportation fee specified in the contract plus any other costs not included in the fee with respect to that transportation that are borne by the producer;

(6) repealed 5/3/2007;

(7) repealed 5/3/2007; or

(8) if transportation of oil or gas is by a nonregulated pipeline facility that is owned or effectively owned, in whole or in part, by the producer of that oil or gas, the sum of the following, allocated to that oil or gas in the proportion that the volume of that oil or gas bears to the total volume of fluids transported by the pipeline:

(A) a cost of capital allowance that includes depreciation and a return on investment, as provided in 15 AAC 55.195(d) ;

(B) the reasonable operating and maintenance costs for the pipeline facility, which are determined by multiplying the projected actual annual amount of direct operating and maintenance costs for the pipeline facility by 112 percent; for purposes of this subparagraph, direct operating and maintenance costs are only those costs necessary to physically operate and maintain the pipeline facility;

(C) ad valorem taxes associated with the pipeline facility.

(c) Repealed 1/1/2000.

(d) Repealed 1/1/2000.

(e) Repealed 1/1/2000.

(f) Repealed 1/1/2000.

(g) Repealed 1/1/2000.

(h) Reasonable cost of transportation under 15 AAC 55.180(b) is fair market value. Fair market value of transportation is determined

(1) for shipments of oil, on the basis of third-party charters (that is, time charters in which the producer does not own or effectively own the vessel in whole or in part) of one year or more which are reported to the department for like vessels, plus regulated transportation costs under (b)(1) of this section; two vessels will be considered like vessels if the difference between them in tonnage is less than 10,000 dead-weight tons and if they are both

(A) Jones Act vessels (46 U.S.C. App. 808 and 883);

(B) Construction-Differential Subsidy ("CDS") vessels (46 U.S.C. App. 1151 - 1161);

(C) Operating-Differential Subsidy ("ODS") vessels (46 U.S.C. App. 1171 - 1185);

(D) CDS and ODS vessels; or

(E) vessels that do not meet the qualifications of (A) - (D) of this paragraph; or

(2) for shipments of gas as LNG, on the basis of third party charters or leases (that is, time charters or leases in which the producer does not own or effectively own, in whole or in part, the LNG transportation facility in question) of three years or more that are reported to

the department for like LNG transportation facilities, plus regulated transportation costs under (b)(1) of this section.

(i) If a producer sells its oil or gas to a third party in what would otherwise be a bona fide, arm's-length sale but at the time of the sale the producer expects to repurchase that oil or gas at a subsequent time and place, then that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it had remained the producer's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production in such a case, the reasonable cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the producer were the shipper. This subsection does not apply if the producer's expected repurchase does not in fact occur.

(j) For purposes of this section, allowable voyage and port costs for a vessel do not include losses, damages, or expenses incurred in connection with an oil discharge except as provided in this subsection, and do not include taxes or fees on the receipt of oil or LNG at a marine terminal from a vessel. Allowable voyage and port costs for a vessel or LNG tanker are costs actually incurred for the following purposes:

(1) fuel for the vessel or LNG tanker while in port and at sea not to exceed the actual cost if purchased from a third party, or if the fuel is not purchased from a third party, the spot market price of comparable fuel as reported in Platt's Oilgram Price Report at the time of the fuel purchase for the market nearest the point of refueling, plus related allowable fuel taxes and handling charges;

(2) stores and provisions for the vessel or LNG tanker and its captain and crew

(3) wages and benefits of the vessel's or LNG tanker's captain and crew;

(4) routine maintenance;

(5) drydocking costs, expensed in the year paid;

(6) port and dock fees;

(7) repealed 1/1/2002;

(8) demurrage;

(9) tug and pilotage fees;

(10) marine agents' fees in port;

(11) lightering;

(12) transshipment charges;

(13) customs fees and duties;

(14) taxes incurred due to the ownership and operation of the vessel or LNG tanker, except for income taxes and other taxes (including certain franchise taxes) measured by income;

(15) regular and customary gratuities that are also legal;

(16) insurance premiums actually paid to third-party insurers;

(17) minor cargo losses or measuring differentials not to exceed .0025 of the oil transported, determined on an annual basis for each vessel;

(18) loading and unloading inspection fees;

(19) Panama Canal transit fees;

(20) a reasonable management fee for operating vessels or LNG tankers; this fee is set at six percent of the allowable costs set out in (1) - (3) of this subsection; this set fee covers all general and administrative costs related to vessel operations, including all costs for accounting services, clerical services, administrative services, secretarial services, data processing services, legal services, corporate and operations management, overhead pass-throughs, facility costs and depreciation, corporate planning, risk management, environmental planning and risk evaluation, public affairs, governmental affairs, political affairs, dues and subscriptions other than dues allowable under (22) of this subsection, long-range scheduling, and long-range planning; additional deductions will not be allowed for these costs;

(21) other costs directly associated with the operation or maintenance of the vessel or LNG tanker, including costs for port services and operations, cargo scheduling and planning, fleet staffing, fleet scheduling, fleet staff training, fleet safety, engineering for repair, engineering for maintenance, engineering for drydocking, quality assurance for vessel operations, communication systems, navigation systems, United States Coast Guard certifications, and utility services; these costs include costs for personnel performing the functions listed and the first level of supervision of these personnel;

(22) costs incurred in transportation of oil to comply with 33 U.S.C. 2701 - 2761 (Oil Pollution Act of 1990), AS 46.04, and applicable laws of this or any other state or political subdivision requiring equipment and personnel to be in place for spill prevention and response to spills from vessels; those costs must have not been incorporated into a pipeline tariff, but must have been incurred as an actual cost in the transportation of oil produced in the state; and

(23) costs of containing and cleaning up cargo lost in a discharge, unless the discharge is a catastrophic oil discharge under AS 46.04.900 .

(k) For purposes of this section, a producer "effectively owns" a vessel, LNG transportation facility, or nonregulated pipeline facility if the vessel, LNG transportation facility, or nonregulated pipeline facility

(1) is owned by another person comprising part of a consolidated business in which the producer is also a part;

(2) is the subject of a lease that qualifies as a capital lease under generally accepted accounting principles, in which the producer or another person comprising part of a consolidated business in which the producer is also a part, is the lessee;

(3) was built to the account of the producer, or of another person comprising part of a consolidated business in which the producer is also a part, was sold and was chartered or leased back by the producer, or by another person comprising part of a consolidated business in which the producer is also a part, all in a simultaneous transaction, and is on a term charter or lease for a period of 15 years or longer to the producer, or to another person comprising part of a consolidated business in which the producer is also a part; or

(4) in the case of a vessel for which a cost of capital allowance is allowed under 15 AAC 55.196, is treated as owned by the producer, or by another person comprising part of a consolidated business in which the producer is also a part, in a federal income tax return filed by or on behalf of the producer, or by or on behalf of another person comprising part of a consolidated business in which the producer is also a part.

(*l*) For purposes of this section, the "positioning cost" for a vessel or LNG tanker includes the costs borne by the producer for placing that vessel or LNG tanker into position before the vessel's or LNG tanker's first voyage in service for that producer.

(m) The third-party nature of an agreement between a producer and a third-party carrier regarding transportation costs is not affected during the term of that agreement by a subsequent consolidation of that producer and carrier into a consolidated business, if, at the time they entered into that agreement, neither the producer nor the carrier exercised directly or indirectly any control over the business affairs of the other.

(n) The producer's actual marine transportation cost, as otherwise determined under this section, for a producer that transports oil produced in the state on behalf of a non-affiliated party through a charter, contract of affreightment, sublease, or other arrangement, in addition to the producer's own oil produced in the state, includes the cost of transporting that non-affiliated party's oil produced in the state and is reduced by the revenue received for providing that transportation. For purposes of this subsection,

(1) "affiliated party" means a company effectively controlled by the producer or by the same company that effectively controls the producer; a company "effectively controls" another company if it directly or indirectly owns 20 percent or more of the outstanding stock or other ownership interests;

(2) "non-affiliated party" means a producer of oil produced in the state that is not an affiliated party.

(o) A producer shall report any reimbursed costs to the department. Reimbursed costs are not allowable as actual costs of transportation under this section.

(p) Only costs incurred in the transportation of oil or gas produced from a lease or property in the state are allowable costs. Costs incurred in connection with the transportation of any other oil or gas are not allowable costs.

(q) For purposes of this section, "expected useful life" means the period of time used to calculate depreciation under (b)(3)(C) or (b)(4)(B)(iii) of this section.

(r) Repealed 1/1/2002.

(s) Repealed 1/1/2000.

(t) Repealed 5/3/2007.

(u) For oil or gas produced during calendar year 2002 that is transported by a vessel placed in service on or after January 1, 1995, the actual costs of transportation under (b) of this section do not include depreciation, return on acquisition cost, or lease or charter payments for a vessel or LNG tanker that has not, during any period of 60 consecutive days or longer, retroactive to the first day of the period, transported oil or gas produced in the state. However, if the vessel is placed in dry dock before the end of the 60-day period, the actual costs of transportation under (b) of this section do not include depreciation, return on investment, or lease or charter payments for the vessel if it has not, during any period of more than 120 consecutive days, transported oil or gas produced in the state, with the disallowance of the costs of transportation starting with the 121st day.

(v) Other costs incurred to transport oil or gas from the flange of the vessel to the sales delivery point are allowable for purposes of 15 AAC 55.180(a) if the other costs are actual costs of transportation.

(w) This section applies to oil and gas produced before July 1, 2007.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164; am 5/3/2007, Register 182; am 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.150

AS 43.55.900

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15 AAC 55.192. Monthly share of annual transportation costs

(a) For purposes of AS 43.55.160 (c), a producer shall determine the appropriate monthly share of the producer's costs of transportation for a calendar year using an acceptable method under this section that the producer chooses for this purpose and applying that method consistently for all months of the calendar year. An acceptable method is

(1) a method that the producer used consistently in calculating its tax under AS 43.55 during calendar year 2005;

(2) any of the following methods as applicable:

(A) for transportation described in 15 AAC 55.191(b) (1), (2), (4)(A), or (5) or 15 AAC 55.193(b) (1), (2), (4)(A), or (5),

(i) use of the actual or reasonable costs of transportation, as applicable, of the oil and gas produced or shipped during the month in question and that are allowable under the applicable provision of 15 AAC 55.191 or 15 AAC 55.193; or

(ii) use of the per barrel, per Mcf, or per MMBTU annual average of the actual or reasonable costs of transportation, as applicable, for the oil or gas produced or shipped during the calendar year and that are allowable under the applicable provision of 15 AAC 55.191 or 15 AAC 55.193;

(B) for transportation described in 15 AAC 55.191(b) (3), (4)(B), or (8) or 15 AAC 55.193(b) (3), (4)(B), or (6), use of the per barrel, per Mcf, or per MMBTU annual average of the actual or reasonable costs of transportation, as applicable, of the oil or gas produced or shipped during the calendar year and that are allowable under the applicable provision of 15 AAC 55.191 or 15 AAC 55.193; or

(3) another method that is approved by the department as fairly representing the appropriate monthly share of the producer's transportation costs for a calendar year.

(b) A producer may not shift transportation costs between months for the purpose of reducing a tax levied by AS 43.55.011 (g), as that provision read on June 30, 2007, or a tax levied by AS 43.55.011 (e).

History: Eff. 5/3/2007, Register 182; am 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.150

AS 43.55.160

15 AAC 55.193. Calculation of costs of transportation for oil and gas produced after June 30, 2007

(a) Costs of transportation are the ordinary and necessary costs incurred to transport the oil or gas from the point of production to the sales delivery point.

(b) Actual costs of transportation under AS 43.55.150 (a) are

(1) if transportation of oil or gas is by a regulated carrier, the tariff rate that is on file with the Regulatory Commission of Alaska or another regulatory agency having jurisdiction, and that is applicable to and paid for that transportation of the oil or gas, from the point where that oil or gas is tendered into the facility of the carrier to the point where it is delivered from the facility of the carrier; for purposes of this paragraph, "carrier" includes a person providing gas treatment in a regulated gas treatment plant;

(2) if transportation of oil is by a vessel that is not owned or effectively owned, in whole or in part, by the producer of that oil

(A) for a single voyage charter, the total costs under the charter for that vessel, plus any voyage and port costs as provided in (d) of this section if those voyage and port costs are incurred for that transportation during the term of the charter, are not included in the charter fee, and are borne by the producer, plus the positioning costs, if any, borne by the producer for that vessel;

(B) for a consecutive voyage charter or a time charter, the total costs under the charter for that vessel, plus any voyage and port costs as provided in (d) of this section if those voyage and port costs are incurred for that transportation during the term of the charter, are not included in the charter fee, and are borne by the producer, plus the positioning cost, if any, borne by the producer for that vessel; the positioning cost must be amortized over the lesser of 36 months or the term of the charter in the case of a time charter, and amortized on the basis of the number of voyages in the case of a consecutive voyage charter; or

(C) for a contract of affreightment, the total costs under the contract, plus any voyage and port costs as provided in (d) of this section if those voyage and port costs are incurred for that transportation during the contract of affreightment, are not included in the charter fee, and are borne by the producer, plus any positioning costs not included in that fee that are incurred with respect to that transportation during the contract of affreightment and that are borne by the producer;

(3) if transportation of oil is by a vessel that is owned or effectively owned, in whole or in part, by the producer of that oil, the sum of

(A) voyage and port costs incurred with respect to that transportation, as provided in (e) of this section;

(B) the positioning cost, amortized over 36 months, for that vessel;

(C) depreciation of the vessel as calculated by the producer for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or as provided in 15 AAC 55.195(a) , (b), or (c) or 15 AAC 55.196, as applicable; and

(D) an amount that, when added to the amount of depreciation allowed under (C) of this paragraph, will provide a reasonable after-tax return on the acquisition cost, as provided in 15 AAC 55.195(a) , of the vessel over its expected useful life as used for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or on the adjusted shipyard cost or invested capital as provided in 15 AAC 55.195(b) or (c) or 15 AAC 55.196, as applicable;

(4) in the case of transportation of gas as liquefied natural gas (LNG) by an LNG transportation facility not subject to tariff regulations of the Federal Energy Regulatory Commission or another federal agency, a state, territory, or possession of the United States, or a foreign nation,

(A) if the producer does not own or effectively own, in whole or in part, the LNG transportation facility, the amount charged to the producer for that LNG transportation;

(B) if the producer owns or effectively owns, in whole or in part, the LNG transportation facility, the sum of

(i) the direct operating costs of the LNG transportation facility incurred with respect to the producer's gas; for an LNG tanker, direct operating costs consist of the tanker's voyage and port costs as provided in (d) of this section;

(ii) the positioning cost, amortized over 36 months, in the case of an LNG tanker;

(iii) depreciation of the LNG transportation facility as calculated by the producer for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or as provided in 15 AAC 55.195(a) , (b), (c), or (d) or 15 AAC 55.196, as applicable;

(iv) an amount that, when added to the amount of depreciation allowed under (iii) of this subparagraph, will provide a reasonable after-tax return on the acquisition cost, as provided in 15 AAC 55.195(a) , (b), (c), or (d), as applicable, of the LNG transportation facility over its expected useful life as used for financial accounting purposes and used for reporting income and expenses to shareholders and owners, or on the adjusted shipyard cost or invested capital as provided in 15 AAC 55.195(a) , (b), (c), or (d) or 15 AAC 55.196, as applicable;

(5) if transportation of oil or gas is by a nonregulated pipeline facility or gas treatment plant that is not owned or effectively owned, in whole or in part, by the producer of that oil or gas, the transportation fee specified in the contract;

(6) if transportation of oil or gas is by a nonregulated pipeline facility or gas treatment plant that is owned or effectively owned, in whole or in part, by the producer of that oil or gas, the costs calculated using the methodology under 15 AAC 55.197.

(c) Reasonable costs of transportation under AS 43.55.150 (b) are determined as follows:

(1) for transportation whose actual costs are calculated under (b)(2) or (4)(A) of this section, reasonable costs of transportation are fair market value; the department will determine the fair market value of the transportation

(A) for shipments of oil, on the basis of third-party charters (that is, time charters in which the producer does not own or effectively own the vessel in whole or in part) of one year or more for like vessels; two vessels will be considered like vessels if the difference between them in tonnage is less than 10,000 dead-weight tons and if they are both

(i) Jones Act vessels (46 U.S.C. 55102 and 57109);

(ii) Construction-Differential Subsidy (CDS) vessels (46 U.S.C. 53101 - 53312);

(iii) Operating-Differential Subsidy (ODS) vessels (46 U.S.C. 53101 - 53517);

(iv) CDS and ODS vessels; or

(v) vessels that do not meet the qualifications of (i) - (iv) of this subparagraph;

(B) for shipments of gas as LNG, on the basis of third party charters or leases (that is, time charters or leases in which the producer does not own or effectively own, in whole or in part, the LNG transportation facility in question) of three years or more for like LNG transportation facilities;

(2) for transportation whose actual costs are calculated under (b)(3) of this section, reasonable costs are the actual costs;

(3) for transportation whose actual costs are calculated under (b)(4)(B) of this section, reasonable costs are the actual costs;

(4) for transportation of gas as LNG by a regulated LNG transportation facility whose actual costs of transportation are calculated under (b)(1) of this section, reasonable costs are determined using the applicable methodology under (b)(4)(B) of this section for calculating actual costs as if the LNG transportation facility were not regulated;

(5) for transportation by a pipeline facility or gas treatment plant, except as otherwise provided under (e) - (j) of this section, reasonable costs are 103 percent of the costs of transportation calculated by the department using the methodology under 15 AAC 55.197.

(d) For purposes of this section, allowable voyage and port costs for a vessel do not include losses, damages, or expenses incurred in connection with an oil discharge except as provided in this subsection, and do not include taxes or fees on the receipt of oil or LNG at a marine terminal from a vessel. Allowable voyage and port costs for a vessel or LNG tanker are costs actually incurred for the following purposes:

(1) fuel for the vessel or LNG tanker while in port and at sea not to exceed the actual cost if purchased from a third party, or if the fuel is not purchased from a third party, the spot market price of comparable fuel as reported in *Platt's Oilgram Price Report* at the time of the fuel purchase for the market nearest the point of refueling, plus related allowable fuel taxes and handling charges;

(2) stores and provisions for the vessel or LNG tanker and its captain and crew;

(3) wages and benefits of the vessel's or LNG tanker's captain and crew;

(4) routine maintenance;

(5) drydocking costs, expensed in the year paid;

(6) port and dock fees;

(7) demurrage;

(8) tug and pilotage fees;

(9) marine agents' fees in port;

(10) lightering;

(11) transshipment charges;

(12) customs fees and duties;

(13) taxes incurred due to the ownership and operation of the vessel or LNG tanker, except for income taxes and other taxes (including certain franchise taxes) measured by income;

(14) regular and customary gratuities that are also legal;

(15) insurance premiums actually paid to third-party insurers;

(16) minor cargo losses or measuring differentials not to exceed .0025 of the oil transported, determined on an annual basis for each vessel;

(17) loading and unloading inspection fees;

(18) Panama Canal transit fees;

(19) a reasonable management fee for operating vessels or LNG tankers; this fee is set at six percent of the allowable costs set out in (1) - (3) of this subsection; this set fee covers all general and administrative costs related to vessel operations, including all costs for accounting services, clerical services, administrative services, secretarial services, data processing services, legal services, corporate and operations management, overhead pass-throughs, facility costs and depreciation, corporate planning, risk management, environmental planning and risk evaluation, public affairs, governmental affairs, political affairs, dues and subscriptions other than dues allowable under (21) of this subsection, long-range scheduling, and long-range planning; additional deductions will not be allowed for these costs;

(20) other costs directly associated with the operation or maintenance of the vessel or LNG tanker, including costs for port services and operations, cargo scheduling and planning, fleet staffing, fleet scheduling, fleet staff training, fleet safety, engineering for repair, engineering for maintenance, engineering for drydocking, quality assurance for vessel operations, communication systems, navigation systems, United States Coast Guard certifications, and utility services; these costs include costs for personnel performing the functions listed and the first level of supervision of these personnel;

(21) costs incurred in transportation of oil to comply with 33 U.S.C. 2701 - 2762 (Oil Pollution Act of 1990), AS 46.04, and applicable laws of this or any other state or political subdivision requiring equipment and personnel to be in place for spill prevention and response to spills from vessels; those costs must have not been incorporated into a pipeline tariff, but must have been incurred as an actual cost in the transportation of oil produced in the state; and

(22) costs of containing and cleaning up cargo lost in a discharge, unless the discharge is a catastrophic oil discharge under AS 46.04.900 .

(e) Except as otherwise provided in this subsection and in (i) of this section, if a tariff rate for pipeline transportation of oil or gas or gas treatment has been adjudicated as just and reasonable by the Regulatory Commission of Alaska or another regulatory agency having jurisdiction, the tariff rate establishes the reasonable costs of the pipeline transportation or gas treatment to which the tariff rate applies, for periods for which the tariff rate is in effect, including periods for which the tariff rate is given retroactive effect. However, the tariff rate does not establish those reasonable costs for any period later than five years after the end of the test period on which the tariff rate is based. If a complaint challenging the tariff rate has been filed with and accepted for investigation by the Regulatory Commission of Alaska or other regulatory agency, the reasonable costs of the pipeline transportation or gas treatment are 103 percent of the costs of transportation calculated by the department using the methodology under 15 AAC 55.197, for the period

(1) that begins on the date the complaint is accepted for investigation and ends the day before the date, if any, that the complaint proceeding is resolved by

(A) the adjudication of an applicable tariff rate as just and reasonable; or

(B) the acceptance by the Regulatory Commission of Alaska or other regulatory agency of a settlement to which the state is a party and that provides for a tariff rate that the department determines uses a cost-based tariff settlement methodology; and

(2) for which a tariff rate described in (1)(A) or (B) of this subsection is not given retroactive effect.

(f) Except as otherwise provided in this subsection and in (i) of this section, if a tariff rate for pipeline transportation of gas or gas treatment has been approved by the Federal Energy Regulatory Commission in connection with issuance of a certificate of public convenience and necessity for the pipeline facility or gas treatment plant, respectively, the tariff rate establishes the reasonable costs of the pipeline transportation or gas treatment to which the tariff rate applies, for periods for which the tariff rate is in effect. However, the tariff rate does not establish those reasonable costs for any period later than three years after the later of the date the tariff rate is approved or the date commercial operation commences. For purposes of this subsection, the date a tariff rate is approved is the date when the Federal Energy Regulatory Commission's final order issuing the certificate of public convenience and necessity becomes effective, regardless of whether the order is subject to judicial review. If a complaint challenging the tariff rate has been filed with and accepted for investigation by the Federal Energy Regulatory Commission, the reasonable costs of the pipeline transportation or gas treatment are 103 percent of the costs of transportation calculated by the department using the methodology under 15 AAC 55.197, for the period

(1) that begins on the date the complaint is accepted for investigation and ends the day before the date, if any, that the complaint proceeding is resolved by

(A) the adjudication of an applicable tariff rate as just and reasonable; or

(B) the Federal Energy Regulatory Commission's acceptance of a settlement to which the state is a party and that provides for a tariff rate that the department determines uses a cost-based tariff settlement methodology; and

(2) for which no rate referred to in (1)(A) or (B) of this subsection is given retroactive effect.

(g) Except as otherwise provided in this subsection and in (h) and (i) of this section, if the department determines that a tariff rate for pipeline transportation of oil or gas or gas treatment on file with the Regulatory Commission of Alaska or another regulatory agency having jurisdiction uses a cost-based tariff settlement methodology, and if the tariff rate is the result of a settlement that is accepted by the Regulatory Commission of Alaska or other regulatory agency and to which the state is a party, the tariff rate establishes the reasonable costs of the pipeline transportation or gas treatment to which the tariff rate applies, for periods for which the tariff rate is in effect, including periods for which the tariff rate is given retroactive effect. However, the tariff rate does not establish those reasonable costs for any period later than the latest of the following dates:

(1) December 31, 2013;

(2) five years after the date the settlement is accepted by the regulatory agency;

(3) three years after the last date that under the settlement the state has the right, beginning no later than five years after the date the settlement is accepted by the regulatory agency and recurring at least once every three years, to require renegotiation or arbitration of material terms of the settlement in response to a material change in rate determination methodologies approved by the regulatory agency, in the economic life of the pipeline facility or gas treatment plant, in capital structure, or in the cost of capital.

(h) Except as otherwise provided in (i) of this section, if a protest or complaint has been filed with and accepted for investigation by the Regulatory Commission of Alaska or another regulatory agency challenging a tariff rate that would otherwise establish the reasonable costs of pipeline transportation or gas treatment under (g) of this section, the reasonable costs of the pipeline transportation or gas treatment are 103 percent of the costs of transportation calculated by the department using the methodology under 15 AAC 55.197, for the period

(1) that begins on the date the protest or complaint is accepted for investigation and ends the day before the date, if any, that the protest or complaint proceeding is resolved by

(A) the adjudication of an applicable tariff rate as just and reasonable; or

(B) the acceptance by the Regulatory Commission of Alaska or other regulatory agency of a settlement to which the state is a party and that provides for a tariff rate that the department determines uses a cost-based tariff settlement methodology; and

(2) for which a tariff rate described in (1)(A) or (B) of this subsection is not given retroactive effect.

(i) If two or more tariff rates for the same category of service for pipeline transportation of oil or gas from a given point of receipt to a given point of delivery are in effect for a calendar year or portion of a calendar year for which each rate would otherwise establish the reasonable costs of the pipeline transportation under (e) - (h) of this section, the reasonable costs of the pipeline transportation for that category of service are equal to the average of all those tariff rates, weighted according to the respective amounts of throughput or, in the case of tariff rates for firm transportation on a gas pipeline facility, the respective amounts of contracted pipeline capacity subject to each of those tariff rates during the calendar year or portion of the calendar year, as applicable.

(j) In the case of an oil or gas pipeline facility as to which the difference between the tariff rate and the reasonable costs of transportation if determined under (c)(5) of this section would not be expected to have a material effect on the production tax liability of producers shipping oil or gas in the pipeline, due to the low volume of oil or gas transported in the pipeline or the low tariff rate, the department may determine that the reasonable costs of transportation equal the tariff rate.

(k) A payment for unused pipeline capacity under a contractual obligation to pay for pipeline capacity whether or not used does not constitute a cost of transportation of oil or gas.

(*l*) If a producer sells its oil or gas to a third party in what would otherwise be a bona fide, arm's length sale but at the time of the sale expects to repurchase that oil or gas at a subsequent time and place, that sale to the third party and the repurchase from the third party, when it occurs, must be disregarded and the oil or gas subject to that sale must be regarded as if it had remained the producer's own oil or gas throughout the time between that sale and repurchase. In determining the value at the point of production of the oil or gas, the cost of transportation between the point of sale for that sale and the point of repurchase must be determined as if the producer were the shipper. This subsection does not apply if the producer's expected repurchase does not in fact occur.

(m) The producer's actual or reasonable marine transportation cost, as otherwise determined under this section, for a producer that transports oil or gas produced in the state through a charter, contract of affreightment, sublease, or other arrangement on behalf of a person not affiliated with the producer, in addition to the producer's own oil or gas produced in the state, includes the cost of transporting that non-affiliated person's oil or gas produced in the state and is reduced by the revenue received for providing that transportation.

(n) Costs that are reimbursed or otherwise offset by payments or credits are not allowable as actual or reasonable costs of transportation. Gas pipeline facility revenues for interruptible transportation, authorized overrun service, or park-and-loan service that the facility does not credit to shippers are considered as credited to the shippers that are affiliated with a person that owns an interest in the facility and that have made firm transportation commitments for the facility; the revenues considered as credited are allocated to these shippers in proportion to the amounts of contracted pipeline capacity under their respective firm transportation commitments. A producer shall report to the department any reimbursements or other payments or credits that offset transportation costs.

(o) The following are not allowable costs of transportation:

(1) a fee or other cost incurred for storage, except for storage

(A) for no more than 30 days if the storage is required under the applicable transportation services agreement with a pipeline facility and is necessary for pipeline operations;

(B) as part of LNG transportation, if the fee or cost is allowed under (b)(4)(B) of this section;

(2) an intra-hub transfer fee paid to a gas pipeline hub operator for administrative services, including accounting for the sale of gas within a hub and title transfer tracking;

(3) a fee paid to a scheduling service provider;

(4) internal costs to schedule, nominate, and account for the sale or movement of oil or gas, if incurred by an entity other than the provider of the transportation services; those costs include salaries and related costs, rent and space costs, office equipment costs, and legal fees;

(5) an aggregator or marketer fee, including a fee a producer pays its affiliate or another person to market, purchase, or resell oil or gas, or find or maintain a market for oil or gas;

(6) a fee paid to a broker, including a fee paid to a person that arranges marketing or transportation;

(7) a penalty incurred as a shipper, including

(A) an over-delivery cash-out penalty, including the difference between the price a pipeline pays for over-delivered volumes outside the tolerances and the price received for over-delivered volumes within the tolerances;

(B) a scheduling penalty, including a penalty incurred for differences between daily volumes delivered into a pipeline and volumes scheduled or nominated at a receipt or delivery point;

(C) an imbalance penalty, including a penalty incurred for differences between volumes delivered into a pipeline and volumes scheduled or nominated at a receipt or delivery point;

(D) an operational penalty, including a fee incurred for violation of a pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline;

(8) a transportation factor listed as reducing the sales price or posted price for a component of gas;

(9) costs of arbitration, litigation, or other dispute resolution activity that involves the state or concerns the rights or obligations

(A) among carriers or owners of a transportation facility; or

(B) between a carrier or owner of a transportation facility and a shipper;

(10) if the producer is affiliated with the carrier or owner of the transportation facility or if the transportation contract otherwise is not at arm's length,

(A) a payment, either volumetric or in value, for actual or theoretical losses of oil or gas;

(B) costs of a surety.

(p) Only costs incurred in the transportation of taxable oil or gas produced from a lease or property in the state are allowable costs. Costs incurred in connection with the transportation of any other oil or gas are not allowable costs.

(q) A producer for which the gross value at the point of production of oil or gas is calculated using the lower of actual costs of transportation or reasonable costs of transportation under AS 43.55.150 shall provide to the department, upon request, information available to the producer that the department considers as necessary to determine the reasonable costs of transportation under this section.

(r) For purposes of AS 43.55.150 (b) and this section, a tariff rate has been adjudicated when the regulatory agency has issued its final order in the adjudication and that order has become effective, regardless of whether the order is subject to judicial review.

(s) For purposes of this section,

(1) a settlement has been accepted by a regulatory agency when the regulatory agency has issued its final order accepting the settlement and that order has become effective, regardless of whether the order is subject to judicial review;

(2) a tariff rate is given retroactive effect for a period beginning on a past date if the regulatory agency having jurisdiction provides that the tariff rate is effective beginning on

that date, regardless of the extent, if any, to which the agency orders refunds with respect to transportation charges paid by shippers during the period;

(3) a cost-based tariff settlement methodology is a methodology

(A) for determining the charge for pipeline transportation of oil or gas or for gas treatment;

(B) that is substantially similar to an adjudicatory methodology used by the Regulatory Commission of Alaska or another regulatory agency having jurisdiction over one or more pipeline tariffs for an oil or gas pipeline in the state;

(C) that provides for periodic true-up of forecast costs with known costs actually incurred; and

(D) that provides for a charge per unit of oil or gas transported or gas treated based solely on recovery of the sum of no more than the following elements of cost:

(i) a return on capital investment calculated by multiplying a specified percentage rate times the amount of capital investment in the transportation facility net of prior accumulated depreciation;

(ii) depreciation of the capital investment in the transportation facility;

(iii) identified elements of operating and maintenance costs and ad valorem taxes incurred, or identified elements of operating and maintenance costs and ad valorem taxes forecast to be incurred;

(iv) income taxes;

(v) an allowance for the cost of dismantlement and removal of the pipeline facility and of restoration after removal of the pipeline facility, if the tariff specifically identifies and provides for the allowance to be included in the applicable recourse rate, in the case of a regulated gas pipeline facility, or the applicable rate, in the case of a regulated oil pipeline facility;

(4) a producer effectively owns a vessel, LNG transportation facility, nonregulated gas treatment plant, or nonregulated pipeline facility if the vessel, LNG transportation facility, nonregulated gas treatment plant, or nonregulated pipeline facility

(A) is owned by another person comprising part of a consolidated business in which the producer is also a part;

(B) is the subject of a lease that qualifies as a capital lease under generally accepted accounting principles, in which the producer or another person comprising part of a consolidated business in which the producer is also a part, is the lessee;

(C) was built to the account of the producer, or of another person comprising part of a consolidated business in which the producer is also a part, was sold and was chartered or leased back by the producer, or by another person comprising part of a consolidated business in which the producer is also a part, all in a simultaneous transaction, and is on a term charter or lease for a period of 15 years or longer to the producer, or to another person comprising part of a consolidated business in which the producer is also a part; or

(D) in the case of a vessel or LNG transportation facility for which a cost of capital allowance is allowed under 15 AAC 55.196, is treated as owned by the producer, or by another person comprising part of a consolidated business in which the producer is also a part, in a federal income tax return filed by or on behalf of the producer, or by or on behalf of another person comprising part of a consolidated business in which the producer is also a part;

(5) "expected useful life" means the period of time used to calculate depreciation under (b)(3)(C) or (4)(B)(iii) of this section;

(6) "positioning cost" for a vessel or LNG tanker includes the costs borne by the producer for placing that vessel or LNG tanker into position before the vessel's or LNG tanker's first voyage in service for that producer;

(7) transportation of gas includes gas treatment.

(t) This section applies to oil and gas produced after June 30, 2007.

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Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.150

AS 43.55.900

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15 AAC 55.195. Return on investment or cost of capital allowance to be used in calculation of costs of transportation for oil or gas, other than certain LNG or vessel transportation costs for oil or gas produced on or after January 1, 2003

(a) For a vessel, LNG transportation facility, or capitalized improvement placed in service before January 1, 1995, by the producer or by a person from whom, directly or through an intermediate transaction of the same nature, the producer later acquired the vessel as part of a larger transfer of both marine and non-marine assets associated with a business merger or acquisition transaction, a reasonable return including depreciation under 15 AAC 55.191(b) (3)(C) and (D), 15 AAC 55.191(b) (4)(B)(iii) and (iv), 15 AAC 55.193(b) (3)(C) and (D), or 15 AAC 55.193(b) (4)(B)(iii) and (iv) is an amount that yields a return on the acquisition cost of the vessel, LNG transportation facility, or capitalized improvement, after federal income tax, of two percent plus the average annual national inflation rate, measured by the compound root of the GNP deflator, during the period between the time the commitment was made to construct or initially acquire the vessel, LNG transportation facility, or capitalized improvement for the purpose of placing it in service and the time when the vessel, LNG transportation facility, or capitalized improvement had been received or delivered and was ready to be placed into service, or if that period fell entirely within a calendar year, during that entire calendar year, except that if the department replaced that rate of return with a different rate of return for a vessel, LNG transportation facility, or capitalized improvement under former 15 AAC 55.190(i), that different rate of return is allowed instead. The allowance for the reasonable return on the acquisition cost is a level annual amount, determined in the year of initial acquisition for the purpose of placement in service, considering the marginal federal corporate income tax rate in effect that year and the contemporaneous and projected federal income tax benefits. If, in subsequent years, the federal tax rate changes, or other events occur that change the available federal income tax benefits, a revised level annual allowance must be calculated to yield the same after-tax return. For purposes of this subsection,

(1) "acquisition cost" means the amount, not to exceed the cost of the vessel, LNG transportation facility, or capitalized improvement when initially acquired for the purpose of placing it in service, capitalized by the item's actual or effective owner under generally accepted accounting principles, including costs of improvements made after the date a vessel or LNG transportation facility was initially placed in service, and reduced by the

(A) cash value of any federal income tax benefits, such as investment tax credit, of acquiring the vessel, LNG transportation facility, or capitalized improvement; and

(B) reasonable salvage value of the vessel, LNG transportation facility, or capitalized improvement;

(2) "after federal income tax" means after applying appropriate adjustments for the federal income tax benefits of owning and operating the vessel, LNG transportation facility, or capitalized improvement; these tax benefits include tax depreciation, foreign tax credits generated by foreign source income derived from the use of the vessel, LNG transportation facility, or capitalized improvement, capital construction fund contributions, and investment tax credits.

(b) For a vessel or LNG transportation facility placed in service on or after January 1, 1995, and before January 1, 2002, or for a capitalized improvement placed in service on or after January 1, 1995, and before January 1, 2002, that extends the life of a vessel or LNG transportation facility, (1) a reasonable return including depreciation under 15 AAC 55.191(b) (3)(C) and (D) or 15 AAC 55.191(b) (4)(B)(iii) and (iv) is $99,000 per year for 24 years for each $1,000,000 of adjusted shipyard cost, for oil or gas produced before January 1, 2002; and (2) a cost of capital allowance will be allowed as provided in (d) or (f) of this section or 15 AAC 55.196, as applicable, for oil or gas produced on or after January 1, 2002. For purposes of this subsection, "adjusted shipyard cost" means the total amount paid to the person building or selling the vessel, LNG transportation facility, or capitalized improvement to the producer, less any investment tax credit taken by the producer, or in the case of an effectively owned vessel or LNG transportation facility, taken by the legal owner of that vessel or facility and passed on in whole or in part to the producer through reduced charter-hire or lease payments, and less any salvage value used by the producer to compute depreciation expense reported to shareholders and owners. If a vessel, LNG transportation facility, or capitalized improvement is acquired through a contract that states the purchase price in terms of a foreign currency, the cost is the equivalent amount in United States dollars as determined by applying the foreign currency exchange rate on the date that the contract is initially signed. If a modification to the purchase price is later made, the foreign currency exchange rate on the date that the modification is signed must be applied to the amount by which the purchase price is changed.

(c) For a capitalized improvement placed in service on or after January 1, 1995 and before January 1, 2002, that does not extend the life of a vessel or LNG transportation facility,

(1) a reasonable return including depreciation under 15 AAC 55.191(b) (3)(C) and (D), 15 AAC 55.191(b) (4)(B)(iii) and (iv), 15 AAC 55.193(b) (3)(C) and (D), or 15 AAC 55.193(b) (4)(B)(iii) and (iv) is $158,000 per year for 10 years for each $1,000,000 of adjusted shipyard cost as defined in (b) of this section, for oil or gas produced before January 1, 2002, and on or after January 1, 2003; and

(2) a cost of capital allowance will be allowed as provided in (d) or (h) of this section, as applicable, for oil or gas produced during calendar year 2002.

(d) For an LNG transportation facility first placed in service by the producer on or after January 1, 1995, and before January 1, 2011, or a capitalized improvement to that facility, a cost of capital allowance that consists of depreciation and a return on acquisition cost will be allowed for oil or gas produced on or after January 1, 2002. The cost of capital allowance under this subsection is also available for a pipeline facility under 15 AAC 55.191(b) (8), or for a capitalized improvement that is made to that facility. However, an improvement to an LNG transportation or pipeline facility that the producer treats as an expense under 26 U.S.C. 179 may not receive a cost of capital allowance under this subsection. The cost of capital allowance under this subsection is an amount to be calculated annually for a calendar year as follows:

(1) the cost of capital allowance is calculated

(A) using the following formula, except as provided in (B) of this paragraph: cost of capital allowance = initial cash flow/(1 - marginal federal tax rate); and

(B) for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002, the cost of capital allowance equals the total after-tax cash flow;

(2) for purposes of the formulas set out in (1) and (8) of this subsection, initial cash flow is calculated using the following formula: initial cash flow = (remaining unrecovered investment - after-tax present value of future tax depreciation benefits)/present value of an ordinary annuity of 1 at the end of n periods, where "n" is years of remaining life at interest rate WACC;

(3) for purposes of the formula set out in (2) of this subsection, remaining unrecovered investment is calculated using the following formula: remaining unrecovered investment = (finance cost - total after-tax cash flow) * ((1 + WACC) *exp.* (portion of year in service * 0.5));

(4) for purposes of the formula set out in (3) of this subsection, finance cost is calculated using the following formula: finance cost = remaining unrecovered investment from the prior year * ((1 + WACC) *exp.* (portion of year in service * 0.5));

(5) the remaining unrecovered investment from the prior year, for purposes of the formula set out in (4) of this subsection, and for

(A) the first year the facility is in service, is the sum of the unrecovered investments for all years the facility is under construction; and

(B) a facility that is in service on January 1, 2002, is calculated using the method set out in this subsection and as if the facility received the cost of capital allowances provided in this section for the facility's years of service before January 1, 2002;

(6) for purposes of (5)(A) of this subsection, an unrecovered investment for a year the facility is under construction is calculated as if the facility were built over a two-year period before the first month the facility is first placed in service, with equal amounts paid each year; unrecovered investment for a year the facility is under construction is calculated using the following formula: unrecovered investment for a year the facility is under construction = total amount paid to the person building or selling the facility to the producer * 0.5 * portion of the calendar year the facility is under construction * finance factor during construction;

(7) for purposes of the formula set out in (6) of this subsection, the finance factor during construction is calculated as if the facility were built over a two-year period before the first month the facility is first placed in service; the finance factor during construction is calculated using the following formulas:

(A) for the portion of the first calendar year of construction, and except as provided in (B) of this paragraph, the finance factor during construction = ((1 + WACC for the first calendar year of construction) = it exp. (portion of the first calendar year the facility is in service * 0.5)) * (1 + WACC for the second calendar year of construction) * ((1 + WACC for the third calendar year of construction) = it exp. (1 - the portion of the first calendar year the facility is in service));

(B) for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, the finance factor during construction is calculated as if the portion of the first calendar year the facility is in service is zero;

(C) for the second calendar year of construction, the finance factor during construction = ((1 + WACC for the second calendar year of construction) *exp.* (0.5)) * ((1 + WACC for the third calendar year of construction) *exp.* (1 - the portion of the first calendar year the facility is in service));

(D) for the portion of the third calendar year of construction, the finance factor during construction = (1 + WACC for the third calendar year of construction) *exp.* ((1 - the portion of the first calendar year the facility is in service) * 0.5);

(8) for purposes of (1)(B) of this subsection and the formula set out in (3) of this subsection, total after-tax cash flow is calculated using the following formula: total after-tax cash flow = initial cash flow + after-tax cash flow of depreciation benefits for that tax year;

(9) for purposes of the formula set out in (8) of this subsection, after-tax cash flow of depreciation benefits for that tax year

(A) except as provided in (B) of this paragraph, is calculated using the following formula: after-tax cash flow of depreciation benefits for that tax year = total amount paid to the person building or selling the facility to the producer * marginal federal tax rate * federal depreciation factor; and

(B) equals zero, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(10) for purposes of the formulas set out in (9) and (12) of this subsection, the federal depreciation factor is the percentage of the total amount paid to the person building or selling the facility to the producer that can be depreciated for federal corporate income tax for the tax year;

(11) for purposes of (2) of this subsection, the after-tax present value of future tax depreciation benefits

(A) except as provided in (B) of this paragraph, is the sum of the discounted annual tax depreciation amounts for each remaining year in which the total amount paid to the person building or selling the facility to the producer can be depreciated for federal corporate income tax for the tax year; and

(B) equals zero, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(12) for purposes of (11) of this subsection, a discounted annual tax depreciation amount is calculated using the following formula: discounted annual tax depreciation amount = federal depreciation factor * total amount paid to the person building or selling the facility to the producer * marginal federal tax rate * discount factor;

(13) for purposes of the formulas set out in (1), (9), and (12) of this subsection, the marginal federal tax rate

(A) except as provided in (B) of this paragraph, is the highest marginal federal corporate income tax rate for the calendar year; if the federal income tax rate changes during the year, the department will apply the new tax rate to that portion for the year that equals the number of days in the year that include and follow the day on which the old tax rate changed, divided by the total number of days in that year; and

(B) equals 35 percent, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(14) for purposes of the formula set out in (12) of this subsection, the discount factor is calculated using the following formula: discount factor = 1/((1 + WACC) *exp.* (discount factor exponent));

(15) for purposes of the formula set out in (14) of this subsection, the discount factor exponent is calculated using the following formula: discount factor exponent = (((((1 - portion of year in service) + 1) * 0.5) - 1) + year depreciation benefit is realized);

(16) for purposes of the formula set out in (2) of this subsection, the present value of an ordinary annuity of 1 at the end of n periods, where "n" is years of remaining life at interest rate WACC, is the result generated by the following formula: (((1 - (1/((1+WACC) *exp.* (years of remaining life))))/WACC)/((1+WACC) *exp.* (-0.5)))/portion of year in service;

(17) for purposes of the formula set out in (16) of this subsection, years of remaining life must be determined for each

(A) component of the facility that is in service at the start-up of the facility as if that component had a 30-year life, except that for LNG transportation facilities first placed in service on or after January 1, 1995 and before January 1, 2002, years of remaining life must be determined, for each year before January 1, 2002, as if that component had a 24-year life;

(B) capitalized improvement that extends the life of a facility and that is put in service after start-up of the facility as if that capitalized improvement had a 15-year life; and

(C) capitalized improvement that does not extend the life of a facility and that is put in service after start-up of the facility as if that capitalized improvement had a 10-year life;

(18) for purposes of the formulas set out in (2), (3), (4), (7), (14), and (16) of this subsection, WACC or the weighted average cost of capital,

(A) for a calendar year before 1997,

(i) except as provided in (ii) of this subparagraph, is 10 percent; and

(ii) is eight percent, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002; and

(B) for 1997 or a later calendar year,

(i) except as provided in (ii) of this subparagraph, is the cost of capital, as reasonably determined by the department, for the category of business described for Standard Industrial Classification (SIC) Industry No. 4924, in the Executive Office of the President, Office of Management and Budget, *Standard Industrial Classification Manual,* as revised as of 1987; as described in this subparagraph, SIC Industry No. 4924 is adopted by reference; in determining a cost of capital for a calendar year under this sub-subparagraph, the department will presume, in the absence of facts to the contrary, that the cost of capital is accurately represented by the weighted average cost of capital using the capital asset pricing model (CAPM), ordinary least squares (OLS) for the industrial composite for SIC code number 4924, as reported in Morningstar Inc., *The Cost of Capital Yearbook* published during the previous calendar year, plus, for LNG transportation facilities, 0.2 percent after December 31, 2001; and

(ii) is eight percent, for an LNG transportation facility first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(19) for purposes of the formula set out in (16) of this subsection, for facilities that come into service midyear, the portion of the year in service for the first and last calendar years the facility is in service is the number of days the facility is in service during the year divided by 365, and 100 percent for all other years.

(e) The following example illustrates (d) of this section:

Taxpayer A places a facility into service in Year One. The total amount paid to the person building or selling the facility is $1,000,000. The facility comes into service 75 percent of the way into Year One; it is in service 25 percent of the year. For the first partial calendar year of construction, the tax rate is 34 percent and the WACC is five percent. For the second full calendar year of construction, the tax rate is 35 percent and the WACC is six percent. For the third partial calendar year of construction, the tax rate is 37 percent and the WACC is eight percent. For the first year of service the tax rate and WACC are the same as for the third year of construction: the tax rate is 37 percent and the WACC is eight percent. The federal depreciation factors are as follows:

Year 1 = 15%

Year 2 = 22%

Year 3 = 21%

Year 4 = 21%

Year 5 = 21%

Because the facility begins service mid-year, the federal depreciation factors are weighted for time in service as follows:

Year 1 = (0.25 * 15%) = 0.0375

Year 2 = (0.75 * 15%) + (0.25 * 22%) = 0.1675

Year 3 = (0.75 * 22%) + (0.25 * 21%) = 0.2175

Year 4 = (0.75 * 21%) + (0.25 * 21%) = 0.2100

Year 5 = (0.75 * 21%) + (0.25 * 21%) = 0.2100

Year 6 = (0.75 * 21%) = 0.1575

Step One: Calculate the finance factor during construction for the three years of construction under (d)(7) of this section:

For the first calendar year of construction the finance factor during construction would be:

(((1 + 0.05) *exp.* (0.25 * 0.5)) * (1 + 0.06) * ((1 + 0.08) *exp.* (1 - 0.25)) = 1.129854044

For the second calendar year of construction the finance factor during construction would be:

(((1 + 0.06) *exp.* (0.5)) * ((1+0.08) *exp.* (1 - 0.25)) = 1.090738767

For the third calendar year of construction the finance factor during construction would be:

(1 + 0.08) *exp.* (((1 - 0.25) * 0.5) = 1.029280887

Step Two: Calculate the unrecovered investment for the three years of construction under (d)(6) of this section:

For the first year of construction the unrecovered investment would be:

1,000,000 * 0.5 * 0.25 * 1.129854044 = 141,232

For the second year of construction the unrecovered investment would be:

1,000,000 * 0.5 * 1.00 * 1.090738767 = 545,369

For the third year of construction the unrecovered investment would be:

1,000,000 * 0.5 * 0.75 * 1.029280887 = 385,980

Step Three: Calculate the remaining unrecovered investment from the prior year for Year One under (d)(5) of this section:

141,232 + 545,369 + 385,980 = 1,072,581

Step Four: Calculate the discount factor exponent for Year One under (d)(15) of this section:

(((((1 - 0.25) + 1) * 0.5) - 1) + 1) = 0.875

Step Five: Calculate the discount factor for Year One under (d)(14) of this section:

1 / ((1 + 0.08) *exp.* (0.875)) = 0.935

Step Six: Calculate the discounted annual tax depreciation amount for Year One under (d)(12) of this section:

0.0375 * 1,000,000 * 0.37 * 0.935 = 12,971

Step Seven: Calculate the after-tax present value of future tax depreciation benefits for Year One under (d)(11) of this section by adding the discounted tax depreciation amounts for the first five complete years:

Year 1 = 0.0375 * 1,000,000 * 0.37 * 0.935 = 12,971

Year 2 = 0.1675 * 1,000,000 * 0.37 * 0.891 = 55,218

Year 3 = 0.2175 * 1,000,000 * 0.37 * 0.825 = 66,390

Year 4 = 0.2100 * 1,000,000 * 0.37 * 0.764 = 59,352

Year 5 = 0.2100 * 1,000,000 * 0.37 * 0.707 = 54,956

Year 6 = 0.1575 * 1,000,000 * 0.37 * 0.655 = 38,164

Total = 287,051.

Table 1 shows the derivation of the after-tax present value of future tax depreciation benefits for Years One - Six.

Step Eight: Calculate the finance cost for Year One under (d)(4) of this section:

1,072,581 * ((1 + 0.08) *exp.* (0.25 * 0.5)) = 1,082,950

Step Nine: Calculate the present value of an ordinary annuity of 1 for Year One under (d)(16) of this section:

(((1 - (1 / ((1 + 0.08) *exp.* (30))))/0.08) / ((1 + 0.08) *exp.* (-0.5)))/0.25 = 46.79773

Step Ten: Calculate the initial cash flow under (d)(2) of this section:

(1,072,581 - 287,051) / 46.79773 = 16,786

Step Eleven: Calculate the cost of capital allowance under (d)(1) of this section:

16,786 / (1 - 0.37) = 26,644

Step Twelve: Calculate the after-tax cash flow of depreciation benefits for Year One under (d)(9) of this section:

1,000,000 * 0.37 * 0.0375 = 13,875

Step Thirteen: Calculate the total after-tax cash flow for Year One under (d)(8) of this section:

16,786 + 13,875 = 30,661

Step Fourteen: Calculate the remaining unrecovered investment at the end of Year One under (d)(3) of this section:

(1,082,950 - 30,661) * ((1 + .08) *exp.* (0.25 * 0.5)) = 1,062,461

Table 2 shows the capital construction allowances for the remaining years using the tax rates and WACCs given in the example.

TABLE 1: AFTER-TAX PRESENT VALUE

OF FUTURE DEPRECIATION BENEFITS

CLICK TO VIEW TABLE

TABLE 2: COST OF CAPITAL ALLOWANCE FOR LNG AND PIPELINE FACILITIES

(continued)

TABLE 2: COST OF CAPITAL ALLOWANCE FOR LNG AND PIPELINE FACILITIES (cont.)

CLICK TO VIEW TABLE

(f) For a vessel first placed in service on or after January 1, 1995, or for an improvement that extends the life of a vessel and that was first placed in service on or after January 1, 1995, a cost of capital allowance that consists of depreciation and a return on investment will be allowed for oil or gas produced during calendar year 2002, except that a producer may elect to expense the first $1,000,000 in costs incurred with respect to improvements during calendar year 2002. An amount expensed may be either deducted in the month incurred or amortized over all months in calendar year 2002. The cost of capital allowance under this subsection is an amount to be calculated annually for a calendar year as follows:

(1) the cost of capital allowance is calculated

(A) using the following formula, except as provided in (B) of this paragraph: cost of capital allowance = after-tax cash flow / (1 - marginal federal tax rate); and

(B) for a vessel that was first placed in service on or after January 1, 1995 and before January 1, 2002, or for a capitalized improvement that extends the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002, the cost of capital allowance equals after-tax cash flow;

(2) for purposes of (1) of this subsection, after-tax cash flow is calculated using the following formula: after-tax cash flow = remaining unrecovered investment from the prior year / present value of an ordinary annuity of 1 at the end of the remaining life at interest rate WACC;

(3) for purposes of the formula set out in (2) of this subsection, remaining unrecovered investment is calculated using the following formula: remaining unrecovered investment = ((mid-year unrecovered investment - after-tax cash flow) * ((1 + WACC) ***exp.* (portion of year in service * 0.5))) - value of any federal tax credits, deductions, or benefits that are allowable under 26 U.S.C. (Internal Revenue Code), including any tax depreciation deductions and capital construction fund benefit, and that were not included in the calculation made under (6)(A) or (C) of this subsection in the year for which the tax is paid;**

(4) for purposes of the formula set out in (2) of this subsection, remaining unrecovered investment for the first year the vessel is in service is the net unrecovered capital investment;

(5) for purposes of the formula set out in (3) of this subsection, mid-year unrecovered investment is calculated using the following formula: mid-year unrecovered investment = remaining unrecovered investment from the prior year * ((1 + WACC) ***exp.*** **(portion of year in service * 0.5));**

(6) for purposes of (4) of this subsection, net unrecovered capital investment is the total amount paid to the person building or selling the vessel to the producer, including any improvements to existing vessels,

(A) minus any investment tax credit taken by the producer under 26 U.S.C. 38 (Internal Revenue Code), or in the case of an effectively owned vessel, as described in 15 AAC 55.191(k) , taken by the legal owner of that vessel or facility and passed on in whole or in part to the producer through reduced charter-hire or lease payments; this subparagraph does not apply to vessels first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(B) minus the after-tax net present value of the salvage value of the vessel in Year 25; this subparagraph does not apply to vessels first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(C) minus the net present value in the first year the vessel is in service of any other federal tax credits, deductions, or benefits allowable under 26 U.S.C. (Internal Revenue Code), including any tax depreciation deductions and capital construction fund benefit, where appropriate; this subparagraph does not apply to vessels first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002; and

(D) plus a return on capital used during construction;

(7) for purposes of (6) of this subsection, a return on capital used during construction is the sum of the yearly construction cost of capital for each year of construction, calculated as if the vessel were built over a two-year period before the first month the vessel is first placed in service, with equal amounts paid each year;

(8) for purposes of the formula set out in (7) of this subsection, yearly construction cost of capital for a year is calculated using the following formula: yearly construction cost of capital = construction unrecovered investment - yearly outlay;

(9) for purposes of the formulas set out in (8) and (10) of this subsection, yearly outlay is calculated as if the vessel were built over a two-year period before the first month the is first

placed in service, with equal amounts paid each year; yearly outlay is calculated using the following formulas:

(A) for the portion of the first calendar year of construction, and except as provided in (B) of this paragraph, yearly outlay = portion of the year in service for the first calendar year the vessel is in service * 0.5 * total amount paid to the person building or selling the vessel to the producer;

(B) for a vessel that was first placed in service on or after January 1, 1995 and before January 1, 2002, or for a capitalized improvement that extends the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, the yearly outlay is calculated as if the portion of the first calendar year the vessel is in service were zero;

(C) for the second calendar year of construction, yearly outlay = 0.5 * total amount paid to the person building or selling the vessel to the producer;

(D) for the portion of the third calendar year of construction, yearly outlay = (1 - the portion of the year in service for the first calendar year the vessel is in service) * 0.5 * total amount paid to the person building or selling the vessel to the producer;

(10) for purposes of the formula set out in (8) of this subsection, construction unrecovered investment is calculated using the following formula: construction unrecovered investment = yearly outlay * construction finance factor during construction;

(11) for purposes of the formula set out in (10) of this subsection, the construction finance factor during construction is calculated using the following formulas:

(A) for the portion of the first calendar year of construction, the construction finance factor during construction = ((1 + WACC for the first calendar year of construction) ***exp.*** **(portion of the first calendar year the vessel is in service * 0.5)) * (1 + WACC for the second calendar year of construction) * ((1 + WACC for the third calendar year of construction)** ***exp.*** **(1 - the portion of the first calendar year the vessel is in service));**

(B) for the second calendar year of construction, the construction finance factor during construction = ((1 + WACC for the second calendar year of construction) ***exp.*** **(0.5)) * ((1 + WACC for the third calendar year of construction)** ***exp.*** **(1 - the portion of the first calendar year the vessel is in service));**

(C) for the portion of the third calendar year of construction, the construction finance factor during construction = (1 + WACC for the third calendar year of construction) ***exp.*** **((1 - the portion of the first calendar year the vessel is in service) * 0.5);**

(12) for purposes of (6) of this subsection, after-tax net present value of the salvage value of the vessel in Year 25 is calculated using the following formula: after-tax net present value of the salvage value of the vessel in Year 25 = 0.04 * total amount paid to the person building or selling the vessel * (1 - marginal federal tax rate for the first year the vessel is in service) * salvage value discount factor;

(13) for purposes of the formula set out in (12) of this subsection, salvage value discount factor is calculated using the following formula: salvage value discount factor = (1 / ((1 + WACC for the first year the vessel is in service) ***exp.*** **(24.5)));**

(14) for purposes of the formula set out in (2) of this subsection, present value of an ordinary annuity of 1 at the end of the remaining life is calculated using the following formula: present value of an ordinary annuity of 1 at the end of the remaining life = (((1 - (1 / ((1 + WACC) ***exp.*** **(years of remaining life)))) / WACC) / ((1 + WACC)** ***exp.*** **(-0.5))) / portion of year in service;**

(15) for purposes of the formula set out in (14) of this subsection, years of remaining life must be determined for a vessel as if the vessel had a 24-year life beginning on the first day of the month that the vessel takes on its first load of oil, and for a capitalized improvement that extends the life of a vessel, as if the capitalized improvement had a 15-year life beginning on the first day of the month that the vessel with the new improvement takes on a load of oil; the life of the vessel or capitalized improvement will not be suspended during periods of lay up or dry dock, while the vessel is not in service, or for any other reason;

(16) for purposes of the formulas set out in (1) and (12) of this subsection, the marginal federal tax rate

(A) except as provided in (B) of this paragraph, is the highest marginal federal corporate income tax rate for the calendar year; if the federal income tax rate changes during the year, the department will apply the new tax rate to that portion for the year that equals the number of days in the year that include and follow the day on which the old tax rate changed, divided by the total number of days in that year; and

(B) equals 35 percent, for a vessel first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(17) for purposes of the formulas set out in (2), (3), (5), (11), (13), and (14) of this subsection, WACC, or the weighted average cost of capital,

(A) except as provided in (B) of this paragraph, is the cost of capital as reasonably determined by the department, for the category of business described for Standard Industrial Classification (SIC) Industry No. 4924, in the Executive Office of the President, Office of Management and Budget, ***Standard Industrial Classification Manual,*** **as revised as of 1987; as described in this subparagraph, SIC Industry No. 4924 is adopted by reference; in determining a cost of capital for a calendar year under this paragraph, the department will presume, in the absence of facts to the contrary, that the cost of capital is accurately represented by the weighted average cost of capital using the capital asset pricing model (CAPM), ordinary least squares (OLS) for the industrial composite for SIC code number 4924, as reported in Ibbotson Associates** ***The Cost of Capital Yearbook*** **published during the previous calendar year, plus 0.4 percent; and**

(B) is eight percent, for a vessel first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(18) for purposes of the formulas set out in (3), (5), (9), and (14) of this subsection, for vessels that are first placed in service by the producer mid-year, the portion of the year in service for the first and last calendar years the vessel is in service is the number of days the vessel is in service during the year divided by 365, and 100 percent for all other years;

(19) vessels first placed in service by the producer on or after January 1, 1995, that were in service for a different producer or for a different person before that date and subject to (a) of this section, continue to be subject to (a) of this section, and the cost of capital allowance set

out in this subsection will not be allowed for those vessels; vessels first placed in service by the producer on or after January 1, 1995, that were in service for a different person before that date and subject to (b) of this section, continue to be subject to (b) of this section through December 31, 2001; after December 31, 2001, the cost of capital allowance set out in this subsection will be allowed for those vessels;

(20) for purposes of (6), (9), and (12) of this subsection, if the total amount paid to the person selling the vessel is not based on an arm's-length, third party transaction, is tied to the receipt of other consideration, or cannot reasonably be established by the taxpayer, the total amount paid to the person selling the vessel is the remaining unrecovered investment of the vessel at the time of the acquisition as determined by the department; in making this determination, the department will consider prices paid for similar vessels and other factors related to the value of the vessel;

(21) for purposes of the formula set out in (14) of this section, for vessels first placed in service by the producer on or after January 1, 1995, that either were in service for a different producer or for a different person before January 1, 1995, or were engaged outside the state in ordinary and necessary operations incurred to transport oil or gas before January 1, 1995, years of remaining life must be determined as if the vessel had a total 24-year life and for a capitalized improvement that extends vessel life as if the capitalized improvement had a total 15-year life; the lives of the vessels or capitalized improvements will be considered to have begun at the first loading of oil and will not be suspended during periods of lay up or dry dock, while the vessel is not in service, or for any reason;

(22) for purposes of (6), (9), and (12) of this subsection, if a vessel is acquired through a contract that states the purchase price in terms of a foreign currency, the cost is the equivalent amount in United States dollars as determined by applying the foreign currency exchange rate on the date that the contract is initially signed; if a modification to the purchase price is later made, the foreign currency exchange rate on the date that the modification is signed must be applied to the amount by which the purchase price is changed.

(g) The following example illustrates (f) of this section:

Taxpayer A first places a vessel in service in Year One. The total amount paid to the person building or selling the vessel is $1,000,000. The vessel comes into service 75 percent of the way into Year One; it is in service 25 percent of the year. For the first partial calendar year of construction, the tax rate is 34 percent and the WACC, including the additional 0.4 percent described in (f)(17)(A) of this section, is nine percent. For the second full calendar year of construction, the tax rate is 35 percent and the WACC is eight percent. For the third partial calendar year of construction, the tax rate is 36 percent and the WACC is seven percent. For the first year of service the tax rate and WACC are the same as for the third year of construction. The net present value of the capital construction fund benefit is $354,034.

This example shows the cost of capital allowance for a vessel carrying oil.

Step One: Calculate the yearly outlay for each calendar year of construction under (f)(9)(A), (B), and (C) of this section:

For the portion of the first year calendar year of construction the yearly outlay would be:

0.25 * 0.5 * 1,000,000 = 125,000

For the second calendar year of construction the yearly outlay would be:

0.5 * 1,000,000 = 500,000

For the portion of the third calendar year of construction the yearly outlay would be:

(1 - 0.25) * 0.5 * 1,000,000 = 375,000

Step Two: Calculate the construction finance factor during construction for each calendar year of construction under (f)(11) of this section:

For the portion of the first calendar year of construction the construction finance factor during construction would be:

((1 + 0.09) *exp.* (0.25 * 0.5)) * (1 + 0.08) * ((1 + 0.07) *exp.* (1 - 0.25)) = 1.148523540

For the second calendar year of construction the construction finance factor during construction would be:

((1 + 0.08) *exp.* (0.5)) * ((1 + 0.07) *exp.* (1 - 0.25)) = 1.093326088

For the portion of the third calendar year of construction the construction finance factor during construction would be:

(1 + 0.07) *exp.* ((1 - 0.25) * 0.5) = 1.025696602

Step Three: Calculate the construction unrecovered investment for each calendar year of construction under (f)(10) of this section:

For the first calendar year of construction the construction unrecovered investment would be:

125,000 * 1.148523540 = 143,565

For the second calendar year of construction the construction unrecovered investment would be:

500,000 * 1.093326088 = 546,663

For the third calendar year of construction the construction unrecovered investment would be:

375,000 * 1.025696602 = 384,636

Step Four: Calculate the yearly construction cost of capital for each calendar year of construction under (f)(8) of this section:

For the first year of construction the yearly construction cost of capital would be:

143,565 - 125,000 = 18,565

For the second year of construction the yearly construction cost of capital would be:

546,663 - 500,000 = 46,663

For the third year of construction the yearly construction cost of capital would be:

384,636 - 375,000 = 9,636

Step Five: Calculate the return on capital used during construction under (f)(7) of this section:

18,565 + 46,663 + 9,636 = 74,865

Step Six: Calculate the salvage value discount factor under (f)(13) of this section:

(1/ ((1 + 0.07) *exp.* (24.5))) = 0.191

Step Seven: Calculate the after-tax net present value of the salvage value of the vessel in Year 25 under (f)(12) of this section:

0.04 * 1,000,000 * (1 - 0.36) * 0.191 = 4,879

Step Eight: Calculate the net unrecovered capital investment under (f)(6) of this section:

1,000,000 - 354,034 + 74,865 - 4,879 = 715,952

Step Nine: Calculate the present value of an ordinary annuity of 1 at the end of the remaining life under (f)(14) of this section:

(((1 - (1 / ((1 + 0.07) *exp.* (24)))) / 0.07) / ((1 + 0.07) *exp.* (-0.5))) / 0.25 = 47.45589

Step Ten: Calculate the after-tax cash flow under (f)(2) of this section:

715,952 / 47.45589 = 15,087

Step Eleven: Calculate the cost of capital allowance under (f)(1) of this section:

15,087 / (1 - 0.36) = 23,573

Step Twelve: Calculate the mid-year unrecovered investment under (f)(5) of this section:

715,952 * ((1 + 0.07) *exp.* (0.25 * 0.5)) = 722,033

Step Thirteen: Calculate the remaining unrecovered investment under (f)(3) of this section:

(722,033 - 15,087) * ((1 + 0.07) *exp.* (0.25 * 0.5)) = 712,951

Table 1 shows the cost of capital allowances for the remaining years using the tax rates and WACCs given in the example.

TABLE 1

COST OF CAPITAL ALLOWANCE FOR VESSELS CARRYING OIL

CLICK TO VIEW TABLE

(h) For an improvement to a vessel that does not extend the life of a vessel and that was first placed in service on or after January 1, 1995, a cost of capital allowance that consists of depreciation and a return on investment will be allowed for oil or gas produced during calendar year 2002, except that a producer may elect to expense the first $1,000,000 in costs incurred with respect to improvements during calendar year 2002. An amount expensed may be either deducted in the month incurred or amortized over all months in calendar year 2002. An improvement that the producer treats as an expense under 26 U.S.C. 179 may not receive a cost of capital allowance under this subsection. The cost of capital allowance under this subsection is an amount to be calculated annually for a calendar year as follows:

(1) the cost of capital allowance is calculated using the following formula: cost of capital allowance = initial cash flow / (1 - marginal federal tax rate);

(2) for purposes of the formula set out in (1) of this subsection, initial cash flow is calculated using the following formula: initial cash flow = (remaining unrecovered investment from the prior year - after-tax present value of future tax depreciation benefits) / present value of an ordinary annuity of 1 at the end of n periods, where "n" is years of remaining life at interest rate WACC;

(3) for purposes of the formula set out in (2) of this subsection, remaining unrecovered investment is calculated using the following formula: remaining unrecovered investment = (finance cost - total after-tax cash flow) * ((1 + WACC) ***exp.*** **(portion of year in service * 0.5));**

(4) for purposes of the formula set out in (3) of this subsection, finance cost is calculated using the following formula: finance cost = remaining unrecovered investment from the prior year * ((1 + WACC) ***exp.*** **(portion of year in service * 0.5));**

(5) for purposes of the formula set out in (4) of this subsection, remaining unrecovered investment from the prior year for the first year the capitalized improvement to a vessel is in

service is the total amount paid to the person building or selling the capitalized improvement to the producer;

(6) for purposes of the formula set out in (3) of this subsection, total after-tax cash flow is calculated using the following formula: total after-tax cash flow = initial cash flow + after-tax cash flow of depreciation benefits for that tax year;

(7) for purposes of the formula set out in (6) of this subsection, after-tax cash flow of depreciation benefits for that tax year is calculated using the following formula: after-tax cash flow of depreciation benefits for that tax year = total amount paid to the person building or selling the capitalized improvement to a vessel to the producer * marginal federal tax rate * federal depreciation factor;

(8) for purposes of the formulas set out in (7) and (11) of this subsection, the federal depreciation factor

(A) except as provided in (B) of this paragraph, is the percentage of the total amount paid to the person building or selling the capitalized improvement by the producer that can be depreciated for federal corporate income tax for the tax year; and

(B) for a capitalized improvement that does not extend the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002, is the percentage allowed on a five-year schedule as follows:

(i) for year one, 15 percent;

(ii) for year two, 22 percent;

(iii) for year three, 21 percent;

(iv) for year four, 21 percent;

(v) for year five, 21 percent;

(9) for purposes of (2) of this subsection, after-tax present value of future tax depreciation benefits is the sum of the discounted annual tax depreciation amounts for each remaining year in which the total amount paid to the person building or selling the pipeline facility to the producer can be depreciated for federal corporate income tax for the tax year;

(10) for purposes of (9) of this subsection, a discounted annual tax depreciation amount is calculated using the following formula: discounted annual tax depreciation amount = federal depreciation factor * total amount paid to the person building or selling the capitalized improvement to a vessel to the producer * marginal federal tax rate * discount factor;

(11) for purposes of the formulas set out in (1), (7), and (10) of this subsection, marginal federal tax rate

(A) except as provided in (B) of this paragraph, is the highest marginal federal corporate income tax rate for the calendar year; if the federal income tax rate changes during the year, the department will apply the new tax rate to that portion for the year that equals the number of days in the year that include and follow the day on which the old tax rate changed, divided by the total number of days in that year; and

(B) equals 37 percent, for a capitalized improvement that does not extend the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(12) for purposes of the formula set out in (10) of this subsection, discount factor is calculated using the following formula: discount factor = 1 / ((1 + WACC) ***exp.*** **(discount factor exponent));**

(13) for purposes of the formula set out in (12) of this subsection, the discount factor exponent is calculated using the following formula: discount factor exponent = (((((1 - portion of year in service) + 1) * 0.5) - 1) + year depreciation benefit is realized);

(14) for purposes of the formula set out in (2) of this subsection, the present value of an ordinary annuity of 1 at the end of n periods, where "n" is years of remaining life at interest rate WACC, is calculated using the following formula: present value of an ordinary annuity

of 1 at the end of n periods = (((1 - (1/ ((1 + WACC) ***exp.*** **(years of remaining life)))) / WACC) / ((1 + WACC)** ***exp.*** **(-0.5))) / portion of year in service;**

(15) for purposes of the formula set out in (14) of this subsection, years of remaining life must be determined for each capitalized improvement to a vessel as if it had a 10-year life beginning on the first day of the month that the vessel with the new improvement takes on a load of oil; the life of the capitalized improvement will not be suspended during periods of lay up or dry dock, while the vessel is not in service, or for any other reason;

(16) for purposes of the formulas set out in (2), (3), (4), (12), and (14) of this subsection, WACC, or the weighted average cost of capital,

(A) except as provided in (B) of this paragraph, is the cost of capital as reasonably determined by the department, for the category of business described for Standard Industrial Classification (SIC) Industry No. 4924, in the Executive Office of the President, Office of Management and Budget, ***Standard Industrial Classification Manual*****, as revised as of 1987; as described in this subparagraph, SIC Industry No. 4924 is adopted by reference; in determining a cost of capital for a calendar year under this paragraph, the department will presume, in the absence of facts to the contrary, that the cost of capital is accurately represented by the weighted average cost of capital using the capital asset pricing model (CAPM), ordinary least squares (OLS) for the industrial composite for SIC code number 4924, as reported in Ibbotson Associates** ***The Cost of Capital Yearbook*** **published during the previous calendar year, plus 0.4 percent; and**

(B) is eight percent, for a capitalized improvement that does not extend the life of a vessel and that was first placed in service on or after January 1, 1995 and before January 1, 2002, for each year before January 1, 2002;

(17) for purposes of the formula set out in (3), (4), (13), and (14) of this subsection, for capitalized improvements to a vessel that come into service mid-year, the portion of the year in service for the first and last calendar years the capitalized improvement to a vessel is in service is the number of days the capitalized improvement to a vessel is in service during the year divided by 365, and 100 percent for all other years;

(18) capitalized improvements to a vessel acquired for service on or after January 1, 1995, that were in service before that date and subject to (a) of this section, continue to be subject to (a) of this section, and the cost of capital allowance set out in this subsection will not be allowed for those capitalized improvements; capitalized improvements to a vessel acquired for service on or after January 1, 1995, that were in service before that date and subject to (b) of this section continue to be subject to (b) of this section through December 31, 2001;

after December 31, 2001, the cost of capital allowance set out in this subsection will be allowed for those capitalized improvements;

(19) for purposes of (5), (7), and (10) of this subsection, if the total amount paid to the person selling the capitalized improvement to a vessel is not based on an arm's-length, third party transaction, is tied to the receipt of other consideration, or cannot reasonably be established by the taxpayer, the total amount paid to the person selling the capitalized improvement to a vessel will be determined by the department; in making this determination, the department will consider prices paid for similar improvements and other factors related to the value of the capitalized improvement;

(20) for purposes of (5), (7), and (10) of this subsection, if a capitalized improvement to a vessel is acquired through a contract that states the purchase price in terms of a foreign currency, the cost is the equivalent amount in United States dollars as determined by applying the foreign currency exchange rate on the date that the contract is initially signed; if a modification to the purchase price is later made, the foreign currency exchange rate on the date that the modification is signed must be applied to the amount by which the purchase price is changed.

(i) The following example illustrates (h) of this section:

Taxpayer A places a capitalized improvement to a vessel into service in Year One. The total amount paid to the person building or selling the improvement is $1,000,000. The improvement comes into service 75 percent of the way into Year One; it is in service 25 percent of the year. For the first year of service the tax rate is 37 percent and the WACC, including the additional 0.4 percent described in (h)(16) of this section, is six percent. The federal depreciation factors are as follows:

Year 1 = 15%

Year 2 = 22%

Year 3 = 21%

Year 4 = 21%

Year 5 = 21%

Because the improvement begins service mid-year, the federal depreciation factors are weighted for time in service as follows:

Year 1 = (0.25 * 15%) = 0.0375

Year 2 = (0.75 * 15%) + (0.25 * 22%) = 0.1675

Year 3 = (0.75 * 22%) + (0.25 * 21%) = 0.2175

Year 4 = (0.75 * 21%) + (0.25 * 21%) = 0.2100

Year 5 = (0.75 * 21%) + (0.25 * 21%) = 0.2100

Year 6 = (0.75 * 21%) = 0.1575

This example shows the cost of capital allowance for an improvement to a vessel carrying oil.

Step One: Calculate the discount factor exponent for Year One under (h)(13) of this section:

(((((1 - 0.25) + 1) * 0.5) - 1) + 1) = 0.875

Step Two: Calculate the discount factor for Year One under (h)(12) of this section:

1 / ((1 + 0.06) *exp.* (0.875)) = 0.950

Step Three: Calculate the discounted annual tax depreciation amount for Year One under (h)(10) of this section:

0.0375 * 1,000,000 * 0.37 * 0.950 = 13,185

Step Four: Calculate the after-tax present value of future tax depreciation benefits for Year One under (h)(9) of this section by adding the discounted tax depreciation amounts for the first five complete years:

Year 1 = 0.0375 * 1,000,000 * 0.37 * 0.950 = 13,185

Year 2 = 0.1675 * 1,000,000 * 0.37 * 0.916 = 56,788

Year 3 = 0.2175 * 1,000,000 * 0.37 * 0.864 = 69,566

Year 4 = 0.2100 * 1,000,000 * 0.37 * 0.816 = 63,365

Year 5 = 0.2100 * 1,000,000 * 0.37 * 0.769 = 59,788

Year 6 = 0.1575 * 1,000,000 * 0.37 * 0.726 = 42,296

Total 304,979.

Table 1 shows the derivation of the after-tax present value of future tax depreciation benefits for Years One - Six.

Step Five: Calculate the finance cost for Year One under (h)(4) of this section:

1,000,000 * ((1 + 0.06) *exp.* (0.25 * 0.5)) = 1,007,310

Step Six: Calculate the present value of an ordinary annuity of 1 for Year One under (h)(14) of this section:

(((1 - (1 / ((1 + 0.06) *exp.* (10)))) / 0.06) / ((1 + 0.06) *exp.* (-0.5)))/ 0.25 = 30.31069

Step Seven: Calculate the initial cash flow under (h)(2) of this section:

(1,000,000 - 304,979)/ 30.31069 = 22,930

Step Eight: Calculate the cost of capital allowance under (h)(1) of this section:

22,930 / (1 - 0.37) = 36,397

Step Nine: Calculate the after-tax cash flow of depreciation benefits for Year One under (h)(7) of this section:

1,000,000 * 0.37 * 0.0375 = 13,875

Step Ten: Calculate the total after-tax cash flow for Year One under (h)(6) of this section:

22,930 + 13,875 = 36,805

Step Eleven: Calculate the remaining unrecovered investment at the end of Year One under (h)(3) of this section:

(1,007,310 - 36,805) * ((1 + .06) *exp.* (0.25 * 0.5)) = 977,600

Table 2 shows the capital construction allowances for the remaining years using the tax rates and WACCs given in the example.

TABLE 1: AFTER-TAX PRESENT VALUE OF FUTURE DEPRECIATION BENEFITS

CLICK TO VIEW TABLE

TABLE 2: COST OF CAPITAL ALLOWANCE FOR IMPROVEMENTS TO VESSELS CARRYING OIL

TABLE 2: COST OF CAPITAL ALLOWANCE FOR IMPROVEMENTS TO VESSELS CARRYING OIL (cont.)

CLICK TO VIEW TABLE

History: Eff. 1/1/2000, Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164; am 5/3/2007, Register 182; am 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.150

Editor's note: The material adopted by reference in 15 AAC 55.195(d) , (f), and (h) from the *Standard Industrial Classification Manual* may be viewed at or obtained from the Department of Revenue, Tax Division, 550 W. 7th Avenue, Suite 500, Anchorage, AK 99501. *The Cost of Capital Yearbook* is published by Morningstar Inc., 225 North Michigan Avenue, Suite 700, Chicago, Illinois 60601.

Before 1/1/2000, Register 152, the substance of 15 AAC 55.195(a) , (b), and (c) was in 15 AAC 55.191(d) , (f), and (g). The history note for 15 AAC 55.195 does not reflect the earlier history of the provisions currently set out at 15 AAC 55.195(a) , (b), and (c).

15 AAC 55.196. Cost of capital allowance to be used in calculation of costs of vessel transportation for oil or gas produced on or after January 1, 2003, other than certain costs pertaining to vessels placed in service before January 1, 1995, and in calculation of transportation costs for gas by an LNG transportation facility placed in service after December 31, 2010

(a) Except if 15 AAC 55.195(a) applies, for oil or gas produced on or after January 1, 2003, a cost of capital allowance that consists of depreciation and a return on invested capital will be allowed under this section, as provided in 15 AAC 55.191 or 15 AAC 55.193, as applicable, for a (1) vessel, or an improvement completed on or after January 1, 2002 to a vessel, owned or effectively owned by the producer; or (2) LNG transportation facility owned or effectively owned by the producer and placed in service after December 31, 2010, or an improvement to that facility. However, a producer may elect to expense the first $1,000,000 in costs incurred with respect to improvements during a calendar year.

(b) A cost of capital allowance under this section for a vessel will be allowed only for days when the vessel is in allowable service, in allowable lay up, or in allowable dry dock.

(c) The following requirements apply to the timing of changes in vessel status:

(1) a vessel changing from operation in allowable service to lay up or operation in alterative service begins lay up or operation in alternative service on the day after the last day of cargo discharge in allowable service;

(2) a vessel changing from operation in alternative service to lay up or operation in allowable service begins lay up or operation in allowable service on the day after the last day of cargo discharge in alternative service;

(3) a vessel changing from lay up to operation in allowable service or operation in alternative service begins operation in allowable service or operation in alternative service on the day after the vessel departs from the location where the vessel was laid up;

(4) a vessel going into dry dock begins dry dock status on the day after the last day of cargo discharge or, if going into dry dock from lay up, on the day after the vessel departs from the location where the vessel was laid up;

(5) a vessel finishing dry dock changes from dry dock status to the immediately subsequent status on the day after the vessel departs the dry dock facility;

(6) a vessel begins operation in allowable service on the day that its useful life begins or, in the case of a used vessel newly acquired by a producer, on the day that its remaining useful life for that producer begins, if the vessel proceeds directly to enter operation in allowable service; otherwise, the vessel begins operation in alternative service on the day specified in this paragraph; for purposes of this paragraph, the beginning of a vessel's useful life or remaining useful life is determined in accordance with generally accepted accounting principles.

(d) With the exceptions set out in this subsection for an LNG transportation facility, a cost of capital allowance under this section must be calculated using the methodology set out in the department's publication *Computation of a Cost-of-Capital Allowance under 15 AAC 55.196, Incorporating Depreciation and Return on Invested Capital for Marine Vessels and Improvements,* Second Edition, dated September 19, 2003 and adopted by reference. In the case of an LNG transportation facility,

(1) the methodology is applied as if the term "vessel" read "LNG transportation facility";

(2) the useful life for purposes of the methodology is 30 years;

(3) the weighted average cost of capital is 0.2 percentage point greater than that otherwise calculated under the methodology.

(e) For purposes of this section,

(1) a vessel is in allowable service if the vessel is

(A) in service within the meaning given in 15 AAC 55.900, except when the vessel is in dry dock; or

(B) idle for a period of fewer than 90 consecutive days immediately before operation in allowable service under (A) of this paragraph; for purposes of this subparagraph, a vessel is not idle if it is in dry dock;

(2) a vessel is laid up if it is idle for a period of 90 or more consecutive days; for purposes of this paragraph, a vessel is not idle if it is in dry dock;

(3) a vessel is in allowable lay up if the vessel is laid up during a calendar year, but only to the extent that the total number of days it is or has been laid up while owned or effectively owned by the producer through the end of that calendar year does not exceed the total number of days it is or has been in allowable service while owned or effectively owned by the producer through the end of that calendar year;

(4) a vessel is in allowable dry dock if the vessel is in dry dock during a calendar year, but only for that fraction of the total days in dry dock that equals the sum of the number of days during the year that the vessel is in allowable service and the number of days during the year that the vessel is in allowable lay up, divided by the sum of the number of days during the year that the vessel is in allowable service, the number of days during the year that the vessel is laid up, and the number of days during the year that the vessel is in alternative service;

(5) a vessel is in alternative service if it is not in lay up, dry dock, or allowable service; and

(6) if necessary to determine a vessel's status during a month, the vessel's status at later times will be considered.

(f) In (b), (c), and (e) of this section, "vessel" includes LNG tanker.

History: Eff. 1/1/2003, Register 164; am 1/1/2004, Register 168; am 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.150

Editor's note: Copies of *Computation of a Cost-of-Capital Allowance under 15 AAC 55.196, Incorporating Depreciation and Return on Invested Capital for Marine Vessels and Improvements*, adopted by reference in 15 AAC 55.196(d) , may be obtained from the Tax Division, Department of Revenue, 550 W. Seventh Ave., Suite 500, Anchorage, Alaska 99501-3566.

15 AAC 55.197. Methodology to determine certain transportation costs for pipelines and gas treatment plants

(a) For transportation of oil or gas for which costs are determined under this section, the applicable costs of transportation are determined for a calendar year by calculating the total amount for the year for the following items and allocating that total, as provided under this section, to the specific quantity of oil or gas transported:

(1) an allowance for operating and maintenance expenses of the facility;

(2) annual depreciation on capital investment in the facility at original cost; except as otherwise provided under (k) of this section, depreciation is calculated using straight-line depreciation over the allowed economic life of the facility;

(3) a return on capital investment in the facility at original cost net of depreciation accumulated before the year of calculation, with the undepreciated capital investment adjusted to account for accumulated deferred income taxes;

(4) income tax on the equity portion of the return under (3) of this subsection as determined under (e) and (f) of this section;

(5) ad valorem taxes on the facility;

(6) an allowance for the cost of dismantlement and removal of the pipeline facility and of restoration after removal of the pipeline facility, if the tariff specifically identifies and provides for the allowance to be included in the applicable recourse rate, in the case of a regulated gas pipeline facility, or the applicable rate, in the case of a regulated oil pipeline facility.

(b) For purposes of (a)(1) of this section, the allowance for operating and maintenance expenses is the amount of expenses actually incurred that

(1) are direct costs of operating and maintaining the facility or are overhead costs directly related to operation and maintenance of the facility; and

(2) in the case of

(A) a gas pipeline facility, are properly reportable as operation and maintenance expenses on the Federal Energy Regulatory Commission's *FERC Financial Report, FERC Form No. 2: Annual Report of Major Natural Gas Companies*, as revised as of March 26, 2010 and adopted by reference (FERC Form 2), or, for a gas pipeline facility not subject to FERC regulation, would be properly reportable as operation and maintenance expenses on FERC Form 2 if the facility were subject to FERC regulation;

(B) an oil pipeline facility, are properly reportable as operation and maintenance expenses on the Federal Energy Regulatory Commission's *FERC Financial Report, FERC Form No. 6: Annual Report of Oil Pipeline Companies*, as revised as of March 26, 2010 and adopted by reference (FERC Form 6), or, for an oil pipeline facility not subject to FERC regulation, would be properly reportable as operation and maintenance expenses on FERC Form 6 if the facility were subject to FERC regulation.

(c) For purposes of (a)(2) and (3) of this section, capital investment in the facility includes an allowance for funds used during construction.

(d) For purposes of calculating annual depreciation under (a)(2) of this section,

(1) the allowed economic life is

(A) in the case of a regulated gas pipeline facility or gas treatment plant, the greater of

(i) the estimated useful life used in calculating the recourse rate in the filed tariff; or

(ii) 25 years;

(B) in the case of a regulated oil pipeline facility, the greater of

(i) the estimated useful life used in calculating the rate in the filed tariff; or

(ii) 25 years;

(C) in the case of a nonregulated pipeline facility or gas treatment plant, the greater of

(i) the estimated useful life used for financial accounting purposes; or

(ii) 25 years;

(2) a change in ownership of an asset does not alter the depreciation schedule established for the original owner;

(3) a capital investment may be depreciated only once, and may not be depreciated below a reasonable salvage value; if specifically identified and provided for in an applicable tariff for a regulated pipeline, the salvage value may be negative, unless the calculation of costs under (a) of this section includes an allowance under (a)(6) of this section for dismantlement and removal of the pipeline facility and restoration after removal of the pipeline facility.

(e) For purposes of calculating the return on capital investment under (a)(3) of this section, the percentage of the capital investment treated as financed with long-term debt is the greater of (1) the percentage actually used by the facility owner to finance the facility; or (2) 70 percent for a gas pipeline facility or gas treatment plant, or 55 percent for an oil pipeline facility. The remainder is treated as financed with equity. The return on the portion of the capital investment treated as financed with long-term debt is the actual cost, if any, of the debt or, in the absence of actual cost, the return computed by the department using the weighted average of the cost of long-term debt for the applicable proxy group designated by the department under (f) of this section.

(f) For purposes of the equity portion of the return on capital investment under (a)(3) of this section, an after-tax rate of return on the percentage of the capital investment treated as financed with equity will be determined by the department for a calendar year using a two-stage discounted cash flow model. In implementing that model, the department will give substantial weight to the Federal Energy Regulatory Commission's Policy Statement in *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, Docket No. PL07-2-000, dated April 17, 2008 and adopted by reference for that purpose, subject to the following:

(1) the department will designate the group of proxy companies from companies that meet the following criteria:

(A) the company is publicly traded;

(B) the company is

(i) a natural gas pipeline company for purposes of determining the rate of return for a gas pipeline facility or gas treatment plant;

(ii) an oil pipeline company for purposes of determining the rate of return for an oil pipeline facility;

(C) the company and its shares are recognized and tracked by Value Line or a similar investment information service;

(D) pipeline operations constitute a high proportion of the company's business;

(E) the company or its predecessor in interest has been in operation for at least three years;

(F) there are estimates by Institutional Brokers' Estimate System established by Thomson Reuters, or similar estimates, of five-year earnings growth for the company;

(G) the company has a history of paying dividends or distributions and is currently paying a dividend or distribution;

(H) the company has not eliminated or announced an intention to eliminate its dividend or distribution;

(2) in determining whether a company meeting the criteria under (1) of this subsection should be included in the group of proxy companies, the department may consider the following factors:

(A) the size of the company's market capitalization;

(B) the company's credit rating;

(C) whether four or more companies have already been selected for inclusion in the proxy group of companies;

(3) the department will calculate the rate of return for a calendar year based on information about the group of proxy companies for a recent 12-month period selected by the department.

(g) For purposes of (a)(4) of this section, the

(1) combined federal and state income tax rate for the year of calculation must be used for a facility located within the United States;

(2) applicable combined foreign income tax rate for the year of calculation must be used for a facility located in another country.

(h) The amounts described in (a)(1) and (4) - (6) of this section must be calculated for every calendar year on the same basis, which may be either

(1) the amounts incurred during, or applicable to, the calendar year of calculation; or

(2) if the facility was

(A) in operation for at least nine months during the calendar year immediately preceding the calendar year of calculation, the amounts incurred during, or applicable to, that immediately preceding calendar year; the amounts are annualized or prorated if necessary to account, respectively, for the facility's being in operation for less than that entire immediately preceding calendar year or less than the entire calendar year of calculation;

(B) not in operation for at least nine months during the calendar year immediately preceding the calendar year of calculation, good-faith estimates of the amounts that will be incurred during, or will be applicable to, the calendar year of calculation; an overestimate or underestimate is deducted from or added to, respectively, the amounts used for the next calendar year.

(i) In the calculation of costs of transportation under this section,

(1) a management fee may not be included;

(2) working capital may not be included in capital investment on which depreciation or a return is calculated.

(j) In the allocation of the total amount calculated under (a) of this section to a specific quantity of oil or gas,

(1) for a regulated gas pipeline facility or regulated gas treatment plant, per-unit transportation costs are based on 100 percent load factor of certificated capacity;

(2) for an oil pipeline facility or nonregulated gas treatment plant, per-unit transportation costs are based on throughput;

(3) for a nonregulated gas pipeline facility, per-unit transportation costs are based on

(A) 100 percent load factor of contracted capacity, if the pipeline provides firm transportation service or firm and interruptible service;

(B) throughput, if the pipeline does not provide firm transportation service or firm and interruptible service;

(4) the costs of different categories of pipeline transportation services or gas treatment plant services bear the same relationship to one another as under the recourse rates in the applicable tariff, in the case of a regulated gas pipeline facility or regulated gas treatment plant, or as under the rates in the applicable tariff in the case of a regulated oil pipeline facility, unless the department determines that relationship is unreasonable; if the department determines that relationship is unreasonable or for an unregulated pipeline facility or gas treatment plant, the department will reasonably allocate costs among different categories of pipeline transportation services or gas treatment plant services;

(5) the costs of pipeline transportation between different pairs of receipt and delivery points bear the same relationship to one another as under the recourse rates in the applicable tariff, in the case of a regulated gas pipeline facility, or as under the rates in the applicable tariff in the case of a regulated oil pipeline facility, unless the department determines that relationship is unreasonable; if the department determines that relationship is unreasonable or for an unregulated pipeline facility, the department will reasonably allocate costs to pipeline transportation between different pairs of receipt and delivery points.

(k) If the tariff rates of a regulated pipeline facility or gas treatment plant have a levelized rate structure, the reasonable costs otherwise calculated under this section will also be calculated using a comparable levelized rate structure.

(*l*) For purposes of the department's determination of reasonable costs of transportation under 15 AAC 55.193(c) (5) and this section, to the extent the department is unable to obtain sufficient information to calculate an item in (a)(1) - (6) of this section, the department may make and use a reasonable estimate.

(m) On or after January 1 of a calendar year during which a producer expects to produce oil or gas the actual costs of transportation of which are required by 15 AAC 55.193(b) (6) to be calculated using the methodology under this section, the producer may request in writing the department's determination of the applicable after-tax rate of return under (f) of this section. The department will provide the department's determination to the producer no later than the later of July 1 of the calendar year or 90 days after the department receives the producer's request.

(n) In this section, "facility" means pipeline facility or gas treatment plant, as applicable.

History: Eff. 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.150

AS 43.55.900

Editor's note: The Policy Statement in *Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity*, Docket No. PL07-2-000, FERC Form 2, and FERC Form 6 may be viewed at the Department of Revenue, Tax Division, 550 W. 7th Avenue, Suite 500, Anchorage, AK 99501, and may be obtained from the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, or on the Federal Energy Regulatory Commission website at www.ferc.gov.

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Article 2
Production Tax Value of Oil and Gas

Section

15 AAC 55.200. Retroactive adjustments

Repealed.

History: Eff. 1/6/80, Register 73; am 1/1/2000, Register 152; repealed 5/3/2007, Register 182

Editor's note: The subject matter of 15 AAC 55.200 has been relocated to 15 AAC 55.820.

15 AAC 55.205. Calculation of production tax values for oil and gas produced before July 1, 2007

(a) A producer or, under AS 43.55.160 (d), an explorer shall calculate a single production tax value for a calendar year, under AS 43.55.160 (a)(1), as the provisions of that paragraph read on June 30, 2007, and for a month, under AS 43.55.160 (a)(2), as the provisions of that paragraph read on June 30, 2007, for each segment.

(b) The provision of AS 43.55.160 (b) that a production tax value may not be less than zero applies to each production tax value calculated for each segment. Adjusted lease expenditures applicable to a segment that exceed the amount of adjusted lease expenditures that may, under AS 43.55.160 (b), be deducted in calculating a production tax value for the segment are considered excess adjusted lease expenditures and, except as otherwise provided under 15 AAC 55.223, may not be reallocated to, or deducted in calculating a production tax value for, a different segment. Excess adjusted lease expenditures relating to the calculation of an annual production tax value, but not a monthly production tax value, may be used to establish a carried-forward annual loss to the extent allowed under AS 43.55.023 (b) and 43.55.160(e).

(c) For purposes of this section,

(1) except as otherwise provided under (2) of this subsection, each of the following is a segment for a producer:

(A) all oil and gas, if any, taxable under AS 43.55.011 (e) that the producer produces from leases or properties in the state that include land north of 68 degrees North latitude;

(B) all oil and gas, if any, taxable under AS 43.55.011 (e) that the producer produces from leases or properties in the state outside the Cook Inlet sedimentary basin no part of which is north of 68 degrees North latitude;

(C) oil, if any, taxable under AS 43.55.011 (e) that the producer produces from each lease or property in the Cook Inlet sedimentary basin; for purposes of this paragraph, oil produced from each lease or property constitutes a separate segment;

(D) gas, if any, taxable under AS 43.55.011 (e) that the producer produces from each lease or property in the Cook Inlet sedimentary basin; for purposes of this paragraph, gas produced from each lease or property constitutes a separate segment;

(2) if a producer or explorer does not produce any oil or gas from leases or properties in the

(A) state that include land north of 68 degrees North latitude, the area of the state north of 68 degrees North latitude is a segment for the producer or explorer;

(B) state outside the Cook Inlet sedimentary basin no part of which is north of 68 degrees North latitude, the area of the state outside the Cook Inlet sedimentary basin and not including any land north of 68 degrees North latitude is a segment for the producer or explorer;

(C) Cook Inlet sedimentary basin, the Cook Inlet sedimentary basin is a segment for the producer or explorer.

(d) For leases or properties in the Cook Inlet sedimentary basin that first commenced commercial production of oil or gas before April 1, 2006, unless otherwise approved or required by the department, the producer shall continue to treat as a single lease or property each tract, group of tracts, participating area, or unit that the producer consistently treated, subject to final audit resolution, as a single lease or property for purposes of calculating an economic limit factor under former AS 43.55.013 . Production of oil or gas from a lease or property in the Cook Inlet sedimentary basin that first commences commercial production of oil or gas on or after April 1, 2006, and that corresponds to a participating area or unit approved by the Department of Natural Resources under AS 38.05.180 , other than a lease or property for which the producer calculated an economic limit factor under former AS 43.55.013 , must be treated as production from a distinct lease or property.

(e) This section applies to oil and gas produced before July 1, 2007.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.160

AS 43.55.165

15 AAC 55.206. Calculation of production tax values for oil and gas produced after June 30, 2007

(a) A producer or, under AS 43.55.160 (d), an explorer shall calculate a single production tax value for a calendar year, under AS 43.55.160 (a)(1), and for a month, under AS 43.55.160 (a)(2), for each segment.

(b) The provision of AS 43.55.160 (b) that a production tax value may not be less than zero applies to each production tax value calculated for each segment. Adjusted lease expenditures applicable to a segment that exceed the amount of adjusted lease expenditures that may, under AS 43.55.160 (b), be deducted in calculating a production tax value for the segment are considered excess adjusted lease expenditures and, except as otherwise provided under 15 AAC 55.224, may not be reallocated to, or deducted in calculating a production tax value for, a different segment. Excess adjusted lease expenditures relating to the calculation of an annual production tax value, but not a monthly production tax value, may be used to establish a carried-forward annual loss to the extent allowed under AS 43.55.023 (b) and 43.55.160(e).

(c) For purposes of this section,

(1) except as otherwise provided under (2) of this subsection, each of the following is a segment for a producer:

(A) all oil and gas, if any, taxable under AS 43.55.011 (e), other than gas subject to AS 43.55.011 (o), that the producer produces from leases or properties in the state that include land north of 68 degrees North latitude;

(B) all oil and gas, if any, taxable under AS 43.55.011 (e), other than gas subject to AS 43.55.011 (o), that the producer produces from leases or properties in the state outside the Cook Inlet sedimentary basin no part of which is north of 68 degrees North latitude;

(C) oil, if any, taxable under AS 43.55.011 (e) that the producer produces from each lease or property in the Cook Inlet sedimentary basin; for purposes of this paragraph, oil produced from each lease or property constitutes a separate segment;

(D) gas, if any, taxable under AS 43.55.011 (e) that the producer produces from each lease or property in the Cook Inlet sedimentary basin; for purposes of this paragraph, gas produced from each lease or property constitutes a separate segment;

(E) gas, if any, taxable under AS 43.55.011 (e) that the producer produces from each lease or property outside the Cook Inlet sedimentary basin and that is used in the state; for purposes of this paragraph, gas produced from each lease or property constitutes a separate segment;

(2) if a producer or explorer does not produce any oil or gas from leases or properties in the

(A) state that include land north of 68 degrees North latitude, the area of the state north of 68 degrees North latitude is a segment for the producer or explorer;

(B) state outside the Cook Inlet sedimentary basin no part of which is north of 68 degrees North latitude, the area of the state outside the Cook Inlet sedimentary basin and not including any land north of 68 degrees North latitude is a segment for the producer or explorer;

(C) Cook Inlet sedimentary basin, the Cook Inlet sedimentary basin is a segment for the producer or explorer.

(d) For leases or properties in the Cook Inlet sedimentary basin that first commenced commercial production of oil or gas before April 1, 2006, unless otherwise approved or required by the department, the producer shall continue to treat as a single lease or property each tract, group of tracts, participating area, or unit that the producer consistently treated, subject to final audit resolution, as a single lease or property for purposes of calculating an economic limit factor under former AS 43.55.013 . Production of oil or gas from a lease or property in the Cook Inlet sedimentary basin that first commences commercial production of oil or gas on or after April 1, 2006, and that corresponds to a participating area or unit approved by the Department of Natural Resources under AS 38.05.180 , other than a lease or property for which the producer calculated an economic limit factor under former AS 43.55.013 , must be treated as production from a distinct lease or property.

(e) Except as otherwise provided under (f) of this section,

(1) for gas used in the state and produced from leases or properties outside the Cook Inlet sedimentary basin that first commenced commercial gas production before April 1, 2006, unless otherwise approved or required by the department, the producer shall continue to treat as a single lease or property each tract, group of tracts, participating area, or unit that the producer consistently treated, subject to final audit resolution, as a single lease or property for purposes of calculating an economic limit factor under former AS 43.55.013 ;

(2) production of gas used in the state from a lease or property outside the Cook Inlet sedimentary basin that first commences commercial production on or after April 1, 2006, and that corresponds to a participating area or unit approved by the Department of Natural Resources under AS 38.05.180 , other than a lease or property for which the producer calculated an economic limit factor under former AS 43.55.013 , must be treated as production from a distinct lease or property.

(f) For purposes of this section and 15 AAC 55.215, a unit outside the Cook Inlet sedimentary basin may be treated as a single lease or property even if it contains multiple participating areas, unless any producer's ownership interests' differ by five percentage points or more between two or more of the participating areas.

(g) This section applies to oil and gas produced after June 30, 2007, and before January 1, 2022.

History: Eff. 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

AS 43.55.160

AS 43.55.165

15 AAC 55.210. Definitions

Repealed.

History: Eff. 1/6/80, Register 73; repealed 1/1/95, Register 132

15 AAC 55.215. Applicability of lease expenditures

(a) For purposes of AS 43.55.160 , a lease expenditure for a calendar year that is a cost of

(1) exploring for, developing, or producing oil or gas deposits located within a lease or property is considered a lease expenditure applicable to oil or gas produced from that lease or property during that calendar year, irrespective of whether any oil or gas is actually produced from that lease or property during that calendar year;

(2) exploring for oil or gas deposits located within land in the state other than a lease or property is considered a lease expenditure applicable to oil or gas produced from leases or properties during that calendar year in the area of the state explored, irrespective of whether any oil or gas is actually produced from leases or properties in that area during that calendar year; for purposes of this paragraph, an area of the state is either

(A) land north of 68 degrees North latitude;

(B) land outside the Cook Inlet sedimentary basin not including any land north of 68 degrees North latitude; or

(C) the Cook Inlet sedimentary basin.

(b) A producer's lease expenditure that is a cost of exploring for, developing, or producing oil or gas deposits located within a lease or property in the Cook Inlet sedimentary basin from which both oil and gas are produced by the producer during the calendar year that the lease expenditure is incurred, is allocated between the oil and gas proportionally to the respective amounts of oil and gas in BTU equivalent barrels produced by the producer from the lease or property during the calendar year and taxable under AS 43.55.011 (e). A producer's lease expenditure that is a cost of exploring for oil or gas deposits located within land in the Cook Inlet sedimentary basin that is not a lease or property is allocated among leases or properties in the Cook Inlet sedimentary basin and between oil and gas produced from each of those leases or properties proportionally to the respective amounts, if any, of oil and gas in BTU equivalent barrels produced by the producer from those leases or properties during the calendar year the lease expenditure is incurred and taxable under AS 43.55.011 (e).

(c) The applicability of a lease expenditure with respect to a geographic location is determined by the location of the oil or gas deposit that is explored for, developed, or produced, and not by the location where the cost in question is incurred.

(d) A producer's lease expenditure that is a cost of exploring for, developing, or producing oil or gas deposits located within a lease or property outside the Cook Inlet sedimentary basin from which both (1) gas used in the state; and (2) oil or other gas are produced by the producer during the calendar year after June 30, 2007 in which the lease expenditure is incurred, is allocated between the categories in (1) and (2) of this subsection proportionally to the respective amounts of gas and of oil or other gas in each category, in BTU equivalent barrels, produced by the producer from the lease or property during the calendar year and taxable under AS 43.55.011 (e).

(e) A producer's lease expenditure that is a cost of exploring for oil or gas deposits located within land that is not a lease or property and is in an area of the state described in (a)(2)(A) or (B) of this section is allocated among (1) gas used in the state produced from each lease or property in that area; and (2) oil and other gas produced from leases or properties in that area, proportionally to the respective amounts, if any, of gas used in the state and of oil or other gas, in BTU equivalent barrels, produced by the producer from the leases or properties during the calendar year after June 30, 2007 in which the lease expenditure is incurred and taxable under AS 43.55.011 (e).

(f) For a unit subject to AS 43.55.165 (j) that is not treated as a single lease or property under 15 AAC 55.206(f) , the total lease expenditures, other than qualified capital expenditures, determined for all leases and properties within the unit under AS 43.55.165 (j) and (k) for a calendar year are allocated, for purposes of 15 AAC 55.206(c) (1)(E), among the participating areas in the unit proportionally to the amounts of operating expenses for that calendar year that are actually attributed by the unit operator to the respective participating areas in billings to the producers that own interests in the unit. For purposes of this subsection, "operating expenses" means costs that are treated as other than capital costs under the applicable unit operating agreement.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

AS 43.55.160

AS 43.55.165

15 AAC 55.220. Oil and gas exploration tax credit

Repealed.

History: Eff. 1/1/2004, Register 168; repealed 5/3/2007, Register 182

Editor's note: The subject matter of 15 AAC 55.220 has been relocated to 15 AAC 55.350.

15 AAC 55.223. Cook Inlet lease expenditures incurred before July 1, 2007

(a) In calculating an annual production tax value for a segment described in 15 AAC 55.205(c) (1)(C) or (D), a producer shall deduct applicable adjusted lease expenditures for the calendar year to the maximum extent that deductibility is allowed under applicable law, including (b) of this section.

(b) For a calendar year for which a limitation under AS 43.55.011 (j) or (k), as the provisions of those subsections read on June 30, 2007, on the tax levied by AS 43.55.011 (e) and (g), as the provisions of those subsections read on June 30, 2007, would have the effect, before reallocation of adjusted lease expenditures under this section, of reducing the producer's tax on oil or gas produced from one or more leases or properties below the amount of the tax that would be levied in the absence of that limitation, the producer shall reallocate under this subsection adjusted lease expenditures that are excess adjusted lease expenditures, if any, under 15 AAC 55.205(b) in the calculation of annual production tax values for segments described in 15 AAC 55.205(c) (1)(C) or (D). The producer shall (1) calculate the total amount of those excess adjusted lease expenditures; (2) multiply that total amount by 20 percent; (3) calculate for each lease or property the amount by which a limitation under AS 43.55.011 (j) or (k), as the provisions of those subsections read on June 30, 2007, would reduce, before reallocation of adjusted lease expenditures under this section, the amount of the producer's tax levied by AS 43.55.011 (e) and (g), as the provisions of those subsections read on June 30, 2007; (4) calculate the total of the reductions calculated under (3) of this subsection for all affected leases or properties; (5) if the amount calculated under (2) of this subsection is greater than the amount calculated under (4) of this subsection, subtract the latter from the former; and (6) multiply the amount, if any, calculated under (5) of this subsection by five. The amount, if any, calculated under (6) of this subsection is the only amount of the excess adjusted lease expenditures applicable to segments described in 15 AAC 55.205(c) (1)(C) or (D) that may be used to establish a carried-forward annual loss, to the extent allowed under AS 43.55.023 (b) and 43.55.160(e). The other excess adjusted lease expenditures applicable to segments described in 15 AAC 55.205(c) (1)(C) or (D) are considered to be reallocated to, and deducted in calculating production tax values for, other segments described in 15 AAC 55.205(c) (1)(C) or (D).

(c) This section applies to lease expenditures incurred before July 1, 2007.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

AS 43.55.160

AS 43.55.165

15 AAC 55.224. Lease expenditures incurred after June 30, 2007, for Cook Inlet and for gas used in the state

(a) For purposes of the calculations required under (b) of this section, in calculating an annual production tax value for a segment described in 15 AAC 55.206(c) (1)(C), (D), or

(E), a producer shall deduct applicable adjusted lease expenditures for the calendar year to the maximum extent that deductibility is allowed under applicable law, including (b) of this section.

(b) For a calendar year for which a limitation under AS 43.55.011 (j), (k), or (o) on the tax levied by AS 43.55.011 (e) has the effect of reducing the producer's tax on oil or gas produced from one or more leases or properties below the amount of the tax that would be levied in the absence of that limitation, the producer shall account under this subsection for adjusted lease expenditures that are excess adjusted lease expenditures, if any, under 15 AAC 55.206(b) in the calculation of annual production tax values for segments described in 15 AAC 55.206(c) (1)(C), (D), or (E). Only the amount, if any, of those excess adjusted lease expenditures that is calculated under (6) of this subsection may be used to establish a carried-forward annual loss under AS 43.55.023 (b). The calculations to be performed for the accounting under this subsection are as follows:

(1) calculate the total amount of excess adjusted lease expenditures subject to this subsection;

(2) multiply that total amount by 25 percent;

(3) calculate for each lease or property the amount by which a limitation under AS 43.55.011 (j), (k), or (o) reduces the amount of the producer's tax otherwise levied by AS 43.55.011 (e);

(4) sum the total of the reductions calculated under (3) of this subsection for all affected leases or properties;

(5) if the amount calculated under (2) of this subsection is

(A) greater than the amount calculated under (4) of this subsection, subtract the latter amount from the former amount;

(B) equal to or less than the amount calculated under (4) of this subsection, consider the amount calculated under this paragraph to be zero;

(6) multiply the amount calculated under (5) of this subsection by four.

(c) This section applies to lease expenditures incurred after June 30, 2007, and before January 1, 2022.

History: Eff. 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

AS 43.55.160

AS 43.55.165

15 AAC 55.225. Oil and gas exploration tax credit claim

Repealed.

History: Eff. 1/1/2004, Register 168; repealed 5/3/2007, Register 182

Editor's note: The subject matter of 15 AAC 55.225 has been relocated to 15 AAC 55.355.

15 AAC 55.230. Qualified exploration expenditures

Repealed.

History: Eff. 1/1/2004, Register 168; repealed 5/3/2007, Register 182

Editor's note: The subject matter of 15 AAC 55.230 has been relocated to 15 AAC 55.360.

15 AAC 55.235. Transfer of a production tax credit certificate

Repealed.

History: Eff. 1/1/2004, Register 168; repealed 5/3/2007, Register 182

Editor's note: The subject matter of 15 AAC 55.235 has been relocated to 15 AAC 55.365.

15 AAC 55.240. Applying production tax credit certificates against production tax liability

Repealed.

History: Eff. 1/1/2004, Register 168; repealed 5/3/2007, Register 182

Editor's note: The subject matter of 15 AAC 55.240 has been relocated to 15 AAC 55.370.

15 AAC 55.245. Lease expenditures under operating agreements

(a) Repealed 12/4/2010.

(b) Repealed 12/4/2010.

(c) Repealed 12/4/2010.

(d) The department will not approve or require use of operating agreements under former AS 43.55.165 (c) or (d).

History: Eff. 5/3/2007, Register 182; am 12/4/2010, Register 196

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.160

AS 43.55.165

AS 43.55.170

15 AAC 55.250. Standards for lease expenditures other than overhead

(a) Costs incurred before July 1, 2007, other than an allowance for overhead expenses under 15 AAC 55.270, are ordinary and necessary costs upstream of the point of production of oil and gas and direct costs of exploring for, developing, or producing oil or gas deposits, under AS 43.55.165 (a), as that provision read on June 30, 2007, only if they are

(1) direct charges under 15 AAC 55.260 incurred for an activity or purpose described in (c) of this section; and

(2) not excluded under AS 43.55.165 (e), as that provision read on June 30, 2007, or under AS 43.55.165 (e)(6) and (19), as amended and enacted by sec. 60, ch. 1, SSSLA 2007, to the extent made retroactive to April 1, 2006, by sec. 74(b), ch. 1, SSSLA 2007.

(b) Costs incurred after June 30, 2007, satisfy the requirements established in AS 43.55.165 (a)(1)(B), as enacted by sec. 58, ch. 1, SSSLA 2007, only if they are

(1) direct charges under 15 AAC 55.260 incurred for an activity or purpose described in (c) of this section; and

(2) not excluded under AS 43.55.165 (e), as amended by sec. 60, ch. 1, SSSLA 2007.

(c) The activities or purposes referred to in (a) and (b) of this section are

(1) conducting a geological or geophysical survey to explore for oil or gas;

(2) performing a geological, geophysical, geotechnical, or geochemical examination or investigation specific to reservoir to support development of that reservoir;

(3) processing or interpreting data acquired from an activity described in (1) or (2) of this subsection to support oil or gas exploration, development, or production operations;

(4) designing, surveying, preparing, constructing, operating, or maintaining a drill site for an exploration well or a well to produce oil or gas or to support oil or gas production;

(5) transporting, mobilizing, or demobilizing a rig, coil tubing unit, or similar equipment, or associated supplies, to and on a drill site to drill or perform downhole operations described in (6) - (8) of this subsection on a well described in (4) of this subsection; demobilization does not include transportation out of the state;

(6) designing, drilling, testing, logging, completing, operating, maintaining, repairing, or suspending a well described in (4) of this subsection;

(7) plugging and abandoning an exploration well, but excluding restoration of the drill site;

(8) plugging a well described in (4) of this subsection, or a portion of the well, for the purpose of redrilling;

(9) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining a facility or equipment, other than a well, if the facility or equipment is

(A) used in oil or gas production operations and handles produced fluids upstream of the point of production or fluids injected in a reservoir for reservoir pressure maintenance, repressuring, or enhanced recovery purposes; and

(B) not a refinery, crude oil topping plant, or other manufacturing facility; for purposes of this subparagraph, "manufacturing facility" does not include a gas processing plant;

(10) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining a communications system for communications between the site of oil or gas exploration, development, or production operations, and the operator's headquarters in the state, and that are necessary for the operations;

(11) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining a field automation system solely dedicated to and specific to a unit or a lease or property and necessary for oil or gas production operations of the unit or the lease or property;

(12) preparing and submitting an application, data, or report necessary to obtain or maintain a governmental permit or similar governmental approval for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in (16) of this subsection;

(13) performing an archaeological, geophysical, or environmental survey or preparing an environmental impact statement required by law or otherwise required by a government agency, or required by an oil and gas lease, for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in (16) of this subsection, or otherwise complying with environmental requirements imposed by law or oil and gas lease for those operations, or for that facility, equipment, or infrastructure;

(14) performing one or more of the following activities with respect to an oil or hazardous substance cleanup contingency plan, fire response plan, or disaster recovery plan required for safe operation or by law or oil and gas lease, for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in (16) of this subsection:

(A) preparing and maintaining the plan;

(B) training personnel or performing practice drills, monitoring, or inspection under the plan;

(C) obtaining and maintaining equipment and supplies required under the plan to be routinely kept on hand;

(15) monitoring and maintaining the safety of personnel located at the site, or in the vicinity, of oil or gas exploration, development, or production operations;

(16) designing, constructing, acquiring, transporting, installing, operating, repairing, or maintaining a facility, equipment, or infrastructure that is located in the vicinity of and is

used to support oil or gas exploration, development, or production operations; that facility, equipment, or infrastructure

(A) includes

(i) camps;

(ii) operations centers;

(iii) laboratories;

(iv) staging pads, roads, bridges, docks, helipads, landing areas, and similar transportation structures;

(v) medical facilities;

(vi) emergency response facilities;

(vii) storage facilities;

(viii) security facilities;

(ix) repair and maintenance shops; and

(x) vehicles;

(B) does not include refineries, topping plants, or other manufacturing facilities.

(d) A cost incurred jointly for both an activity or purpose described in (c) of this section and an activity or purpose not described in (c) of this section must be allocated between the activity or purpose described in (c) of this section and the other activity or purpose using a reasonable allocation methodology.

(e) Costs incurred before July 1, 2007, that satisfy the requirements of (a)(1) and (2) of this section are not a producer's or explorer's lease expenditures under AS 43.55.165 (a), as that provision read on June 30, 2007, unless the costs are costs, incurred by the producer after March 31, 2006, of exploring for, developing, or producing oil or gas deposits located within the producer's leases or properties in the state or, in the case of land in which the producer or explorer does not own a working interest, are costs, incurred by the producer or explorer after March 31, 2006, of exploring for oil or gas deposits located within other land in the state.

(f) Costs incurred after June 30, 2007, that satisfy the requirements of (b)(1) and (2) of this section are not a producer's or explorer's lease expenditures under AS 43.55.165 (a), as repealed and reenacted by sec. 58, ch. 1, SSSLA 2007, unless the costs also satisfy the requirements of AS 43.55.165 (a)(1)(A), as enacted by sec. 58, ch. 1, SSSLA 2007.

(g) For purposes of this section, "designing" is limited to activities specific to an identifiable well, facility, item of equipment, or system, and does not include activities of more general applicability or that would ordinarily be considered research and development.

History: Eff. 2/27/2010, Register 193; am 12/4/2010, Register 164

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.160

AS 43.55.165

AS 43.55.170

15 AAC 55.260. Direct charges

(a) Except as limited by (d) and (e) of this section, direct charges for purposes of 15 AAC 55.250(a) and (b) are

(1) costs paid to real property owners to acquire surface rights in real property located in the vicinity of oil or gas exploration, development, or production operations, and used in support of those operations;

(2) net profit shares required to be paid to the state under leases issued under AS 38.05.180 (f)(3)(B), (D), or (E) and paid after June 30, 2007;

(3) labor costs, not including work on tax, legal, purchasing, or accounting matters, or matters involving a dispute before a government agency, in the form of salaries and wages of

(A) employees of the operator, when those employees are directly employed in or in support of oil or gas exploration, development, or production operations, and

(i) on the site or in the vicinity of those operations;

(ii) in transit to or from the site or vicinity of those operations;

(iii) on a site of a system described in 15 AAC 55.250(c) (10) or (11) if assigned to and working on that system; or

(iv) on the site of the construction, transportation, repair, or maintenance of a facility, a system, equipment, or infrastructure described in 15 AAC 55.250(c) (9) - (11) or (16) if assigned to and working on that construction, transportation, repair, or maintenance; or

(B) any of the following employees of the operator, while those employees are assigned to a specific lease or property or unit that is the subject of oil or gas exploration, development, or production, and only as to that portion of the salaries and wages attributable to the time actually devoted to that exploration, development, or production, as supported by an approved timesheet or other time writing document:

(i) technical employees having special and specific engineering, geological, or other technical skills, including engineers, geologists, geophysicists, environmental specialists, and other technical personnel whose primary function with respect to that exploration, development, or production is the handling of specific problems or operating conditions involving the oil or gas exploration, development, or production operations or the support of those operations;

(ii) employees engaged in developing field automation systems dedicated to and specific to a unit or a lease or property and necessary for oil or gas production operations of the unit or the lease or property;

(iii) employees engaged in developing computer applications specific to a unit or a lease or property and necessary for oil or gas development or production operations of the unit or the lease or property;

(4) costs of employee training that directly relates to the job duties for the employees described in (3) of this subsection; the costs of professional memberships, dues, or periodicals, or of education or training in pursuit of an academic degree or professional credential, are not direct charges;

(5) expenditures or contributions made under assessments imposed by governmental authority that are applicable to the operator's labor costs described in (3) of this subsection; as to workers' compensation, if the operator self-insures, it may treat as an expenditure or contribution under this paragraph the charge that is regularly recorded as an accrual in the operator's general ledger as representing the fair and reasonable cost of the self-insurance;

(6) reasonable expenses incurred or reimbursed by the employer of those employees described in (3) of this subsection for travel by those employees to or from the site or vicinity of oil or gas exploration, development, or production operations, and for associated living quarters and meals; a reasonable per diem allowance, if paid by the employer in place of reimbursement of actual expenses, may be substituted for actual expenses for living quarters and meals;

(7) the employer's share of contributions to established plans for employee group life, disability, or medical insurance, pension, retirement, stock purchase, thrift, bonus, or other similar benefit plans, applicable to the operator's labor costs described in (3) of this subsection, if

(A) the plans are available on a regular basis to all employees of the operator who are directly working in oil or gas exploration, development, or production operations, other than employees excluded from a plan's coverage because of participation under a collective bargaining agreement; and

(B) the amount of the employer's share of contributions does not exceed the following percentage, as applicable, of the costs under (3) of this subsection incurred for employees covered by the plans:

(i) 32 percent for calendar year 2006;

(ii) 33 percent for calendar year 2007;

(iii) 36 percent for calendar year 2008;

(iv) 35 percent for calendar year 2009;

(v) 30 percent for a calendar year after 2009;

(8) the employer's share of contributions to established plans for employee group life, disability, or medical insurance, pension, retirement, stock purchase, thrift, bonus, or other

similar benefit plans, applicable to the operator's labor costs described in (3) of this subsection, and available to employees under a collective bargaining agreement;

(9) costs to purchase or transport a facility, equipment, materials, or supplies used in oil or gas exploration, development, or production operations;

(10) costs to purchase or transport a facility, a system, equipment, or infrastructure described in 15 AAC 55.250(c) (10), (11), or (16), or to purchase or transport equipment, materials, or supplies used in a facility, a system, equipment, or infrastructure described in 15 AAC 55.250(c) (10), (11), or (16);

(11) costs paid to a third party for contract services, utilities, or use of a facility equipment, or infrastructure provided by the third party and used in oil or gas exploration, development, or production operations, or used in support of those operations, or for use of a system described in 15 AAC 55.250(c) (10) or (11) provided by the third party; for purposes of this paragraph,

(A) contract services

(i) do not include work in tax, legal, or accounting matters, or matters involving a dispute before a government agency;

(ii) are limited to services the labor costs of which, under (3) of this subsection, would be allowable as direct charges if the operator's employees performed the services;

(B) support facilities, equipment, and infrastructure are limited to the categories described in 15 AAC 55.250(c) (16);

(12) costs charged to a unit or other joint operation for use in its oil or gas exploration, development, or production operations of a facility or equipment that

(A) is wholly or partly owned by a producer or explorer with an interest in the unit or other joint operation; and

(B) is not, and has not previously been, wholly or partly owned or acquired by or on behalf of the unit or other joint operation;

(13) a premium paid to a third-party insurer for insurance covering oil or gas exploration, development, or production operations;

(14) standby costs paid to a third party drilling rig contractor, and incurred

(A) while rig operations are deferred, suspended, or curtailed by reason of force majeure or another cause beyond the reasonable control of the operator; or

(B) to secure a rig for drilling if the rig is actually used for the operation for which it was secured;

(15) payments of property taxes, sales or use taxes, motor fuel taxes, or excise taxes if incurred with respect to the sale, acquisition, ownership, or use of a good, service, or property, the cost of which is a lease expenditure under AS 43.55.165 , or would be a lease expenditure if incurred during the period for which the payment is made;

(16) payments in lieu of property taxes, sales or use taxes, motor fuel taxes, or excise taxes that would otherwise be incurred with respect to the sale, acquisition, ownership, or use of goods, services, or property, the cost of which is a lease expenditure under AS 43.55.165 , or would be a lease expenditure if incurred during the period for which the payment is made;

(17) a regulatory cost charge under AS 31.05.093 ;

(18) a fee charged by a government agency for a regulatory license, permit, or similar regulatory approval required for oil or gas exploration, development, or production operations, or for a facility, equipment, or infrastructure described in 15 AAC 55.250(c) (16);

(19) costs to transport to the injection site, oil, gas, or other fluid recovered from a well and injected for reservoir pressure maintenance, repressuring, or enhanced recovery purposes, and costs paid to a third party producer to purchase that oil, gas, or other fluid from the producer;

(20) if a producer owns a refinery or crude oil topping plant that is located on or near the premises of the producer's lease or property in the state and that processes the producer's oil produced from that lease or property into a product that the producer uses in the operation of the lease or property in drilling for or producing oil or gas, the amount calculated by subtracting from the fair market value of the product used the prevailing value of the oil that is processed; for purposes of this paragraph,

(A) the amount of the oil that is processed equals the number of barrels of the product into which the oil is processed;

(B) the prevailing value of the oil that is processed in a field topping plant in the Alaska North Slope area is the gross value at the point of production of that oil as determined under 15 AAC 55.163(b) ;

(21) costs paid to a third party to acquire geological or geophysical data used in oil or gas exploration, development, or production operations.

(b) For purposes of this section, an employee's salary or wages for a given period of time includes the cost in salary or wages for the employee's earned or compensatory time off attributable to the employee's work during that time period.

(c) In the absence of evidence to the contrary, and for purposes of AS 43.55.165 (e)(12), the department will accept a charge under (a)(12) of this section as being not more than fair market value if the charge does not exceed the cost calculated on the basis of the net book value of the equipment or facility multiplied by the number of hours, days, miles, or throughput volumes for which the equipment or facility is used in the oil or gas exploration, development, or production operations, divided by the number of hours, days, miles, or throughput volumes, as applicable, of estimated remaining useful life of the equipment or facility, or calculated using another method approved by the department. For purposes of this subsection, "net book value" means the dollar amount the owner of an asset records in its financial statements, consistent with generally accepted accounting principles, as the historical cost of the asset, excluding capitalized interest and net of accumulated depreciation or amortization, if the historical cost does not exceed the fair market value of the asset at the time it was acquired by the owner.

(d) Except for a cost described in (a)(2), (13), or (19) of this section, a cost that relates to the exploration, development, or production of oil or gas deposits that are subject to a unit operating agreement or other agreement that provides for an operator to conduct the oil or gas exploration, development, or production on behalf of itself and other producers or explorers is not a direct charge under this section if the cost is not (1) incurred in the first instance by the operator on behalf of the producers or explorers under the agreement; (2) actually billed to the producers or explorers under the agreement; and (3) paid, as to the producer's or explorer's share, by the producer or explorer to whom that share is billed. For purposes of this subsection, an agreement includes an instrument or arrangement among the parties to the agreement that modifies a party's rights or obligations under the agreement.

(e) A fee or other consideration paid to, or for the benefit of, a producer in connection with the use of a facility in which that producer has an ownership interest or in connection with the producer's management of a facility is not a direct charge under this section to the extent that the fee or other consideration

(1) compensates that producer for the deferral or loss of that producer's oil or gas production resulting from the payer's use of the facility; or

(2) reimburses that producer for its additional tax liability resulting from the receipt of a fee or other consideration in connection with the payer's use of the facility or in connection with the producer's management of the facility.

(f) Direct charges under this section are net of any credits, refunds, reimbursements, purchase discounts, and cost recoveries, unless the credit, refund, reimbursement, or cost recovery is accounted for as an adjustment to lease expenditures under AS 43.55.170 . For purposes of this subsection, "credits" do not include tax credits.

(g) For purposes of this section, "operator" means, in the case of

(1) a producer or explorer carrying out oil or gas exploration, development, or production on behalf of itself, that producer or explorer;

(2) a unit operating agreement or other agreement that provides for an operator to carry out oil or gas exploration, development, or production on behalf of itself and other producers or explorers, the producer or explorer acting as operator under that agreement.

History: Eff. 2/27/2010, Register 193; am 12/4/2010, Register 196

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.160

AS 43.55.165

AS 43.55.170

15 AAC 55.270. Overhead before March 1, 2010

(a) This subsection applies only to determining allowable overhead expenses under AS 43.55.165 (a) and (b), as those provisions read on June 30, 2007, and under AS 43.55.165 (a), as repealed and reenacted by see. 58, ch. 1, SSSLA 2007. For purposes of AS 43.55.165 (b)(1)(C), as that provision read on June 30, 2007, and AS 43.55.165 (a)(2), as repealed and reenacted by sec. 58, ch. 1, SSSLA 2007, a reasonable allowance for a producer's or explorer's overhead expenses directly related to exploring for, developing, or producing oil or gas deposits located within a lease or property or other land in the state is the sum of

(1) three percent of the producer's or explorer's non-overhead lease expenditures that are qualified capital expenditures; and

(2) nine percent of the producer's or explorer's non-overhead lease expenditures that are not

(A) qualified capital expenditures;

(B) payments of or in lieu of taxes; or

(C) net profit share payments under 15 AAC 55.260(a) (2).

(b) Repealed 12/4/2010.

(c) Repealed 12/4/2010.

(d) An allowance for overhead expenses is not a qualified capital expenditure.

(e) The provisions of (a)(2)(C) of this section apply to expenditures incurred after June 30, 2007.

(f) This section applies to expenditures incurred before March 1, 2010.

History: Eff. 5/3/2007, Register 182; am 2/27/2010, Register 193; am 12/4/2010, Register 196

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.165

15 AAC 55.271. Overhead on or after March 1, 2010

(a) For purposes of AS 43.55.165 (a)(2), as repealed and reenacted by sec. 58, ch. 1, SSSLA 2007, a reasonable allowance for the calendar year for a producer's or explorer's overhead expenses directly related to exploring for, developing, or producing oil or gas deposits located within a lease or property or other land in the state is 4.5 percent of the producer's or explorer's lease expenditures, net of adjustments under AS 43.55.170 , that are incurred during the calendar year and that are allowed as direct charges under 15 AAC 55.260, excluding

(1) payments of or in lieu of taxes other than

(A) payroll taxes under 15 AAC 55.260(a) (3);

(B) sales taxes, use taxes, or excise taxes on goods or services;

(2) net profit share payments under 15 AAC 55.260(a) (2).

(b) An allowance for overhead expenses is not a qualified capital expenditure.

(c) This section applies to expenditures incurred on or after March 1, 2010.

History: Eff. 2/27/2010, Register 193

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.165

15 AAC 55.275. Exclusions from lease expenditures

(a) The portion of a producer's expenditures incurred during a calendar year before 2022 that is excluded under AS 43.55.165 (e)(18) is calculated separately for each segment under 15 AAC 55.205 or 15 AAC 55.206, as applicable. Subject to prorating for only a portion of a calendar year as provided under AS 43.55.165 (e)(18), the excluded portion for a segment is $1 less than the product of $.30 multiplied by the total amount of taxable

(1) oil and gas, in BTU equivalent barrels, produced by the producer from leases or properties corresponding to the segment described in 15 AAC 55.205(c) (1)(A) or 15 AAC 55.206(c) (1)(A), as applicable, for that segment;

(2) oil and gas, in BTU equivalent barrels, produced by the producer from leases or properties corresponding to the segment described in 15 AAC 55.205(c) (1)(B) or 15 AAC 55.206(c) (1)(B), as applicable, for that segment;

(3) oil, in BTU equivalent barrels, produced by the producer from a lease or property corresponding to a segment described in 15 AAC 55.205(c) (1)(C) or 15 AAC 55.206(c) (1)(C), as applicable, for that segment;

(4) gas, in BTU equivalent barrels, produced by the producer from a lease or property corresponding to a segment described in 15 AAC 55.205(c) (1)(D) or 15 AAC 55.206(c) (1)(D), as applicable, for that segment;

(5) gas, in BTU equivalent barrels, produced by the producer after June 30, 2007, from a lease or property corresponding to a segment described in 15 AAC 55.206(c) (1)(E), for that segment.

(b) The portion of a producer's expenditures that is excluded for a segment under AS 43.55.165 (e)(18) may not exceed the total amount of expenditures that would be qualified capital expenditures applicable to the segment but for the exclusion provided under AS 43.55.165 (e)(18).

(c) For purposes of AS 43.55.165 (e)(18) and (a) of this section, taxable oil or gas is all oil or gas produced from a lease or property in the state except oil and gas the ownership or right to which is exempt from taxation

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.110

AS 43.55.165

15 AAC 55.280. Adjustments to lease expenditures

(a) In adjusting a producer's or explorer's lease expenditures for the receipt of a payment or credit for the sale or other transfer of an asset under AS 43.55.170 (a)(3)(A), if the acquisition cost of the asset was incurred during a calendar year for which a portion of the producer's or explorer's expenditures was excluded under AS 43.55.165 (e)(18) and 15 AAC 55.275, the amount required to be subtracted from the producer's or explorer's lease expenditures under AS 43.55.170 (a) is reduced by a fraction of the payment or credit received for the sale or transfer of the asset as provided in this section. That fraction is equal to the quotient of (1) the total of the excluded portions of the producer's or explorer's expenditures described in this section for all segments in the state under 15 AAC 55.205 or 15 AAC 55.206, as applicable, divided by (2) the sum of the (A) producer's or explorer's qualified capital expenditures incurred with respect to all segments in the state during the calendar year or portion of the calendar year for which that excluded portion was excluded, plus (B) the amount described in (1) of this subsection.

(b) A fee or other consideration received by a producer or by an operator acting for the producer in connection with a person's use of a production facility in which the producer has an ownership interest or in connection with the producer's management of a production facility does not constitute a payment or credit for the use or management of the production facility under AS 43.55.170 (a)(1) or a reimbursement or similar payment that offsets the producer's lease expenditures under AS 43.55.170 (a)(2), to the extent that the fee or other consideration

(1) reimburses the producer for the share of the producer's costs to operate or maintain the production facility that is attributable to another person's use of the facility, except to the extent the producer treats that share of the costs as the producer's lease expenditure;

(2) compensates the producer for the deferral or loss of the producer's oil or gas production resulting from another person's use of the production facility;

(3) reimburses the producer for the producer's additional tax liability resulting from the receipt of a fee or other consideration in connection with another person's use of the production facility or in connection with the producer's management of the production facility; or

(4) in the case of a production facility in which the producer has an ownership interest,

(A) consists of a contribution of a share of new capital investment to acquire, construct, or improve the production facility, and is in lieu of an increase in the fee that would otherwise be charged to the person making the contribution in connection with that person's use of the facility, except to the extent the producer treats that person's share of the capital investment as the producer's lease expenditure; or

(B) constitutes a charge, as determined under (d) of this section, for use of capital invested in the production facility before April 1, 2006.

(c) For purposes of (b)(1) of this section,

(1) costs to operate or maintain the production facility do not include costs that are treated as capitalized expenditures under 26 U.S.C. (Internal Revenue Code), as amended;

(2) except as otherwise provided in (3) of this subsection, if the facility use agreement or management agreement between the person using the facility and the producer provides for an identifiable amount of a fee that represents the person's share of the costs to operate or maintain the production facility, that amount will be considered the share of the producer's costs to operate or maintain the production facility that is attributable to the person's use of the facility;

(3) if the facility use agreement or management agreement between the person using the facility and the producer does not provide for an identifiable amount of a fee representing the person's share of the costs to operate or maintain the production facility, or if the department determines that, under a facility use agreement or management agreement executed after December 31, 2009, or under an amendment executed after December 31, 2009, to a facility use agreement or management agreement, the identifiable amount of a fee purporting to represent the person's share of the costs to operate or maintain the production facility (A) overstates those costs; or (B) fails to reasonably reflect the relative quantities of produced fluids processed by the facility and differences in other characteristics, if any, of the produced fluids that materially affect the costs to operate or maintain the facility, the department will determine the share of the producer's costs to operate or maintain the production facility that is attributable to the person's use of the facility, using a method of allocation that is based on relative quantities of produced fluids processed by the facility and differences in other characteristics, if any, of the produced fluids that materially affect the costs to operate or maintain the facility.

(d) For purposes of (b)(4)(B) of this section, the extent of a fee or other consideration in connection with a person's use of a production facility for a given time period that constitutes a charge for use of capital invested in the production facility before April 1, 2006, is equal to the following:

F x (CB/ (CB + CA)),

where

(1) F equals the total amount of the fee or other consideration, excluding amounts described in (b)(1), (2), (3), or (4)(A) of this section, regardless of whether treated as a lease expenditure, that would be charged for that given time period in connection with the person's use of the facility if the total were calculated on the same per-unit basis that was used to calculate the total fee or other consideration for the

(A) last time period beginning before April 1, 2006, for which the person was charged a fee or other consideration in connection with the person's use of the facility, but not exceeding the amount of the actual total fee or other consideration for the given time period for which the calculation is made; or

(B) first time period for which the person was charged a fee or other consideration for use of the facility, if that first time period began after March 31, 2006, but not exceeding the amount of the actual total fee or other consideration for the given time period for which the calculation is made;

(2) CB equals the producer's total capital investment, if any, incurred before April 1, 2006, to acquire, construct, or improve the production facility, without deduction of depreciation; the producer's capital investment excludes any contribution described in (b)(4)(A) of this section, regardless of whether treated as a lease expenditure; and

(3) CA equals the producer's total capital investment, if any, incurred after March 31, 2006, and before the beginning date of the first time period for which the person was charged a fee in connection with the person's use of the facility, to acquire, construct, or improve the production facility, without deduction of depreciation; the producer's capital investment excludes any contribution described in (b)(4)(A) of this section, regardless of whether treated as a lease expenditure.

(e) For purposes of AS 43.55.170 (a)(1), if a producer treats as the producer's lease expenditure a fee or other consideration that the producer pays or imputes to or on behalf of itself, whether directly or through an operator's billing, in connection with the producer's use of a production facility that the producer owns in whole or in part or that the producer manages, that fee or other consideration constitutes a payment or credit received by the producer for the use by another person of a production facility in which the producer has an ownership interest or for the management by the producer of a production facility under a management agreement providing for the producer to receive a management fee.

(f) For purposes of AS 43.55.170 (a)(2), a payment, credit, or portion of a payment or credit received by or on behalf of a producer to reimburse the producer for a cost passed through to another person does not constitute a reimbursement or similar payment that offsets the producer's lease expenditures if the reimbursed producer does not treat that cost as the producer's lease expenditure.

(g) For purposes of AS 43.55.170 (a)(3), a fee or other consideration received by or on behalf of a producer in connection with another person's use of a production facility in which the producer has an ownership interest does not constitute a payment or credit for the sale or transfer of an asset,

(1) if the fee or other consideration

(A) consists of a contribution of a share of new capital investment to acquire, construct, or improve the production facility and is in lieu of an increase in the fee that would otherwise be charged in connection with use of the facility; or

(B) represents a charge for use of capital invested in the production facility; and

(2) unless legal title or a similar ownership interest in the facility is transferred from the producer.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192; am 12/4/2010, Register 196

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.110

AS 43.55.165

AS 43.55.170

15 AAC 55.290. When cost is incurred

(a) Unless otherwise provided under (c) of this section, for purposes of AS 43.55.165 and this chapter, a cost incurred by a producer or explorer is incurred during the calendar year

(1) for which the operator of a lease or property bills the producer for the cost, if

(A) the cost is a cost of exploring for, developing, or producing oil or gas deposits located within the lease or property;

(B) the operator operates the lease or property on behalf of the producer; and

(C) at least one producer, other than the operator, on behalf of which the operator operates the lease or property has a material interest in the lease or property;

(2) in which the cost is recorded on the producer's or explorer's financial accounting books or federal income tax books as incurred or, in the case of a cost that is treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code), as amended, regardless of elections made under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, as placed in the producer's or explorer's work-in-process, construction-in-process, or similar account, if

(A) a material portion of the cost is not billed to at least one non-operator producer by the operator of a lease or property with respect to whose oil or gas exploration, development, or production the cost is incurred; and

(B) the producer's or explorer's fiscal year for financial accounting purposes or federal income tax purposes, as applicable, is the calendar year;

(3) in which the cost is recorded on the producer's or explorer's financial accounting books as incurred after those books have been restated on a calendar year basis using a method approved or prescribed by the department, if the circumstances are other than those described in (1) or (2) of this subsection.

(b) If a cost is subject to (a)(2) of this section, the producer or explorer may elect to rely on either its financial accounting books or its federal income tax books, but that election once made may not be changed without the department's approval. An election under this subsection

(1) is solely for the purpose of determining during which calendar year a cost is incurred; and

(2) does not affect the categorization of a lease expenditure as a qualified capital expenditure or as not a qualified capital expenditure under AS 43.55.023 (k).

(c) For purposes of AS 43.55.023 (i), AS 43.55.165 , and this chapter, whether a cost incurred by a producer or explorer was incurred before April 1, 2001, or after March 31, 2001, before April 1, 2006, or after March 31, 2006, and before July 1, 2007, or after June 30, 2007, is determined by the month

(1) for which the operator of a lease or property contemporaneously billed the producer for the cost, if

(A) the cost is a cost of exploring for, developing, or producing oil or gas deposits located within the lease or property;

(B) the operator operated the lease or property on behalf of the producer; and

(C) at least one producer, other than the operator, on behalf of which the operator operated the lease or property had a material interest in the lease or property;

(2) in which the cost was contemporaneously recorded on the producer's or explorer's financial accounting books as incurred or, in the case of a cost that is treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code), as amended, regardless of elections made under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, as placed in the producer's or explorer's work-in-process, construction-in-process, or similar account, if the circumstances were other than those described in (1) of this subsection.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.110

AS 43.55.165

Sec. 72, ch. 1,

SSSLA 2007

Article 3
Tax Credits

Section

15 AAC 55.305. Application of tax credits

(a) A producer may apply a tax credit as allowed by law only against the specified type of tax liability. A producer may not apply a tax credit against a penalty or interest.

(b) If a provision of AS 43.55, as that chapter read on June 30, 2007, or this chapter refers to application of a tax credit against a tax liability under AS 43.55.011 (e) but not also AS

43.55.011 (f), the tax credit may not be applied against the minimum tax for oil and gas produced before July 1, 2007, from leases or properties in the state north of 68 degrees North latitude determined under AS 43.55.011 (f), as that subsection read on June 30, 2007. Nothing in this subsection prevents a producer from applying a tax credit based on a lease expenditure applicable to oil and gas produced from those leases or properties against a tax on oil or gas produced from leases or properties elsewhere in the state.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.023

AS 43.55.024

AS 43.55.025

AS 43.55.110

15 AAC 55.310. Qualified capital expenditure credits

For purposes of AS 43.55.023 (a) and (k), if an expenditure incurred by a producer or explorer during a calendar year is an outlay for work-in-progress with respect to an asset the cost of which is treated as a capitalized expenditure under 26 U.S.C. (Internal Revenue Code), as amended, regardless of elections made under 26 U.S.C. 263(c) (Internal Revenue Code), as amended, the fact that the asset is not placed in service until a later calendar year does not prevent the expenditure from constituting a qualified capital expenditure.

History: Eff. 5/3/2007, Register 182

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.110

15 AAC 55.315. Carried-forward annual loss credits

A carried-forward annual loss tax credit under AS 43.55.023 (b) may not be applied against a tax liability for the calendar year in which the adjusted lease expenditures on which the credit is based are incurred.

History: Eff. 5/3/2007, Register 182

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.110

AS 43.55.160

15 AAC 55.320. Transferable tax credit certificates

(a) A producer or explorer may apply for a transferable tax credit certificate for

(1) a qualified capital expenditure credit under AS 43.55.023 (a) at any time after the qualified capital expenditure in question is incurred but no more frequently than once a calendar quarter;

(2) a carried-forward annual loss credit under AS 43.55.023 (b) no earlier than January 1 of the calendar year following the calendar year in which the carried-forward annual loss in question is incurred.

(b) Information and documentation that the department will require a producer or explorer to provide in an application for a transferable tax credit certificate under AS 43.55.023 (d) include

(1) the applicant's certification, under oath, that the expenditures for which the credit is claimed have been incurred, that the credit has not been used, and that the applicant is aware of no reason why the applicant does not qualify for the credit;

(2) a list of any authorizations for expenditure that apply to the expenditures for which the credit is claimed and copies of those authorizations;

(3) a schedule of the relevant expenditures incurred, identifying any applicable authorizations for expenditure and showing the accounts charged and, in the case of expenditures included in a joint interest billing, the month billed;

(4) a description of the lease or property or other land where the exploration, development, or production activities with respect to which the relevant expenditures were incurred took place, and a map or survey showing the location of the activities;

(5) if the relevant expenditures include costs associated with drilling a well, a

(A) copy of

(i) the Well Completion or Recompletion Report and Log (Form 10-407) filed with the Alaska Oil and Gas Conservation Commission under 20 AAC 25.070; or

(ii) a well completion report that is filed with a federal agency and that is substantially similar to the filing described in (i) of this subparagraph; or

(B) well status report, if at the time the application is made material described in (A) of this paragraph is not yet due to be filed and has not been filed;

(6) if the lease or property where the exploration, development, or production activities with respect to which the relevant expenditures were incurred took place is subject to a unit operating agreement, identification of the applicable unit operating agreement;

(7) a list of any partners or other entities that shared in costs of which the relevant expenditures incurred by the applicant are the applicant's share;

(8) if the relevant expenditures are subject to joint venture audit by a participant in a joint venture, identification of and contact information for the joint interest auditor; and

(9) in the case of a qualified capital expenditure incurred in connection with geological or geophysical exploration or in connection with a well,

(A) the applicant's written agreements described in AS 43.55.023 (a)(2)(A); and

(B) documentation that the applicant has submitted to the Department of Natural Resources all data referred to in AS 43.55.023 (a)(2)(B).

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.110

15 AAC 55.325. Cash purchases of tax credit certificates

(a) Repealed 10/21/2009.

(b) Repealed 10/21/2009.

(c) For purposes of AS 43.55.028 (e)(4), an unpaid delinquent tax is an amount of tax for which the department has issued an assessment that has not been paid and, if contested, has not been finally resolved in the producer's favor.

(d) If the total amount of purchases of tax credit certificates for which applicants qualify at any time under AS 43.55.028 (e) exceeds the amount of available money in the oil and gas tax credit fund, the department will give priority to earlier-received applications for purchases. However, on the first business day of each calendar year, previously received outstanding applications will be considered, for purposes of that priority only, to have been received on that first business day. Among applications for purchases received on a given day, the department if necessary will allocate available money pro rata.

(e) Interest does not accrue with respect to any purchase of a tax credit certificate under AS 43.55.028 (e).

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.028

AS 43.55.110

15 AAC 55.330. Transitional investment expenditure credits

(a) Except as provided under (b) of this section, a tax credit under AS 43.55.023 (i)(2) may not be taken for a calendar year after 2006 based on a transitional investment expenditure that is not included in the statement described in 15 AAC 55.345(g) , except for an expenditure that

(1) would have been recognized as a transitional investment expenditure but for the fact that the producer or explorer treated it as an expense for federal income tax purposes before April 1, 2008; and

(2) the United States Internal Revenue Service subsequently required to be capitalized under 26 U.S.C. (Internal Revenue Code), as amended.

(b) A person that did not have commercial production of oil or gas from a lease or property in the state before January 1, 2008, and that wishes to take a tax credit under AS 43.55.023 (i)(2) may not take a tax credit under AS 43.55.023 (i)(2) based on a transitional investment expenditure that is not included in the statement described in 15 AAC 55.345(g) , except for an expenditure that

(1) would have been recognized as a transitional investment expenditure but for the fact that the producer or explorer treated it as an expense for federal income tax purposes before the statement was filed with the department; and

(2) the United States Internal Revenue Service subsequently required to be capitalized under 26 U.S.C. (Internal Revenue Code), as amended.

(c) The exclusion of certain expenditures as provided under AS 43.55.165 (e)(18) and 15 AAC 55.275 applies to the calculation of a producer's transitional investment expenditures incurred during a calendar year or, as prorated under AS 43.55.165 (e)(18), during the last nine months of 2001 or the first three months of 2006. The portion that is excluded is a single amount calculated for the total of the producer's expenditures that would otherwise be transitional investment expenditures, irrespective of the lease or property or area of the state with respect to which the expenditure was incurred. Subject to prorating as applicable, the excluded portion for a calendar year is $1 less than the product of $.30 multiplied by the total amount of taxable oil and gas, in BTU equivalent barrels, produced by the producer from all leases or properties in the state during that calendar year. However, the excluded portion for a calendar year may not exceed the total amount of the producer's expenditures incurred during that calendar year that, but for the exclusion provided under AS 43.55.165 (e)(18), would be qualified capital expenditures if they were incurred after March 31, 2006. For purposes of applying the exclusion under this subsection,

(1) oil and gas are considered to be produced from a lease or property according to

(A) AS 43.55, as that chapter read on March 31, 2006; and

(B) this chapter, as it read on March 31, 2006;

(2) "gas" has the meaning given in AS 43.55.900 , as that section read on March 31, 2006;

(3) "oil" has the meaning given in AS 43.55.900 , as that section read on March 31, 2006; and

(4) "taxable oil and gas" means all oil and gas produced from a lease or property in the state except oil and gas the ownership or right to which is exempt from taxation.

History: Eff. 5/3/2007, Register 182

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.110

AS 43.55.165

15 AAC 55.335. Additional nontransferable credits

(a) For the last nine months of calendar year 2006,

(1) the maximum tax credit that a producer may take under AS 43.55.024 (a) is $4,500,000;

(2) for purposes of AS 43.55.024 (c), the average amount of oil and gas produced a day by a producer is calculated only for the last nine months of the calendar year;

(3) the maximum tax credit that a producer may take under

(A) AS 43.55.024 (c)(1) is $9,000,000;

(B) AS 43.55.024 (c)(2) is $9,000,000 multiplied by the fraction set out in AS 43.55.024 (c)(2).

(b) For a calendar year during which two or more producers that qualify under AS 43.55.024 (e) are succeeded through merger, acquisition, or a similar transaction by a single producer that qualifies under AS 43.55.024 (e),

(1) each of the predecessor producers may take that percentage of an entire credit to which it is otherwise entitled under AS 43.55.024 (a) or (c) that equals the percentage of days in the calendar year during which those producers are separate entities or, for a transaction occurring in 2006, the percentage of days in the last nine months of 2006, during which those producers are separate entities;

(2) the successor producer may take that percentage of a single entire credit to which it is otherwise entitled under AS 43.55.024 (a) or (c) that equals the percentage of days in the calendar year during which that producer is the successor to the predecessor producers or, for a transaction occurring in 2006, the percentage of days in the last nine months of 2006 during which that producer is the successor to the predecessor producers.

(c) An application under AS 43.55.024 (e) must be filed with the department, as part of the statement described in AS 43.55.030 (a), on or before March 31 of the calendar year after the calendar year for which the producer seeks the department's determination that the producer was qualified under AS 43.55.024 . The application must include

(1) the producer's certification that the producer's operation in the state or its ownership of an interest in a lease or property in the state as a distinct producer is not for the purpose of dividing among multiple producer entities any production tax liability under AS 43.55.011 (e) or, for a period before July 1, 2007, under AS 43.55.011 (f), as that subsection read on June 30, 2007, that would otherwise be attributed to a single producer;

(2) information requested on the application form prescribed by the department concerning the producer's transactions or relationships affecting

(A) interests in leases or properties in the state;

(B) rights to oil or gas production from leases or properties in the state; and

(C) interests in other business entities or interests of other business entities in the producer; and

(3) other pertinent information required by the department.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.024

AS 43.55.030

AS 43.55.110

15 AAC 55.340. Cook Inlet credit provisions before July 1, 2007

(a) For purposes of AS 43.55.011 (m), as the provisions of that subsection read on June 30, 2007, the portion of a tax credit for the calendar year of production that is allocated to gas produced by a producer during a calendar year from leases or properties in the Cook Inlet sedimentary basin is, for a credit under

(1) AS 43.55.024 (c), a fraction whose numerator is the amount of gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties in the Cook Inlet sedimentary basin and whose denominator is the total amount of oil and gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties in the state;

(2) AS 38.05.180 (i), AS 41.09.010 , or AS 43.55.025 for an expenditure incurred for exploration in the Cook Inlet sedimentary basin and that is available to be applied for the calendar year of production, a fraction whose numerator is the amount of gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties in the Cook Inlet sedimentary basin and whose denominator is the amount of oil and gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties in the Cook Inlet sedimentary basin;

(3) AS 38.05.180 (i), AS 41.09.010 , or AS 43.55.025 for an expenditure incurred for exploration outside the Cook Inlet sedimentary basin, zero;

(4) AS 43.20.043 or AS 43.55.024 (a), zero.

(b) Except for excess tax credits remaining after reduction as determined under AS 43.55.011 (m)(4), as the provisions of that paragraph read on June 30, 2007, and under (c) and (d) of this section, a tax credit required to be allocated under AS 43.55.011 (m) and (n), as the provisions of those subsections read on June 30, 2007, to gas produced by a producer during a calendar year from leases or properties in the Cook Inlet sedimentary basin

(1) may be applied, if at all, only against the tax levied by AS 43.55.011 (e) for that gas;

(2) to the extent not applied as described in (1) of this subsection, is not available to be used as a tax credit in any manner and is considered lost.

(c) The only types of tax credits that may be included in a determination of excess tax credits under AS 43.55.011 (m), as the provisions of that subsection read on June 30, 2007, are tax credits under AS 38.05.180 (i), AS 41.09.010 , and AS 43.55.025 . In calculating excess tax credits, the total amount of the portions of the tax credits under AS 38.05.180 (i), AS 41.09.010 , and AS 43.55.025 that are allocated to gas produced from leases or properties in the Cook Inlet sedimentary basin during the calendar year is compared to the total amount of tax levied for that gas by AS 43.55.011 (e), as the provisions of that subsection read on June 30, 2007, after application of any limitation under AS 43.55.011 (j), as the provisions of that subsection read on June 30, 2007. If the former amount exceeds the latter amount, the difference is the amount of excess tax credits. After the amount of excess tax credits, if any, has been reduced under AS 43.55.011 (m)(3), as the provisions of that paragraph read on June 30, 2007, the remaining amount of excess tax credits, if any, is treated as a credit under AS 43.55.025 to the extent, if any, that the producer correctly included a credit under AS 43.55.025 in determining excess tax credits, and the balance of the remaining amount of excess tax credits is treated as a credit under AS 38.05.180 (i) or AS 41.09.010 .

(d) If a producer's excess adjusted lease expenditures are required to be reallocated under 15 AAC 55.223(b) , then for purposes of AS 43.55.011 (m)(3), as the provisions of that paragraph read on June 30, 2007, the total calculated under AS 43.55.011 (m)(2), as the provisions of that paragraph read on June 30, 2007, is replaced by

(1) zero, if the amount calculated under 15 AAC 55.223(b) (2) is greater than or equal to the amount calculated under 15 AAC 55.223(b) (4);

(2) the remainder calculated by subtracting the amount calculated under 15 AAC 55.223(b) (2) from the amount calculated under 15 AAC 55.223(b)(4), if the former amount is less than the latter amount.

(e) A tax credit under AS 38.05.180 (i), AS 41.09.010 , or AS 43.55.025 is subject to AS 43.55.011 (m), as the provisions of that subsection read on June 30, 2007, and (a) - (c) of this section if the person that originally qualified for the tax credit fails to transfer the tax credit to another person before or during the calendar year that the credit becomes available to be applied against a tax levied by AS 43.55.011 (e) for gas produced from leases or properties in the Cook Inlet sedimentary basin. If the tax credit is transferred to another person before or during that calendar year, the transferee's use of the tax credit is not subject to AS 43.55.011 (m), as the provisions of that subsection read on June 30, 2007, or (a) - (c) of this section, irrespective of whether the transferee produces gas from a lease or property in the Cook Inlet sedimentary basin. For purposes of this subsection, a tax credit under AS 43.55.025 is not available to be applied against a tax until the department has issued a production tax credit certificate for the credit under AS 43.55.025 (f)(5).

(f) At the request of the person seeking a production tax credit certificate under AS 43.55.025 (f), the department will defer issuing a certificate that is otherwise ready for issuance in December of a calendar year until January of the next calendar year.

(g) This section applies to oil and gas produced and expenditures incurred before July 1, 2007.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.024

AS 43.55.025

AS 43.55.110

15 AAC 55.341. Credit provisions after June 30, 2007, for Cook Inlet and for gas used in the state

(a) For purposes of AS 43.55.011 (m) and this section, the portion of a tax credit for the calendar year of production that is allocated to gas produced by a producer during a calendar year from leases or properties

(1) in the Cook Inlet sedimentary basin is, for a credit under

(A) AS 43.55.024 (c), a fraction whose numerator is the amount of gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties in the Cook Inlet sedimentary basin and whose denominator is the total amount of oil and gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties in the state;

(B) AS 38.05.180 (i), AS 41.09.010 , or AS 43.55.025 for an expenditure incurred for exploration in the Cook Inlet sedimentary basin and that is available to be applied for the calendar year of production, a fraction whose numerator is the amount of gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties in the Cook Inlet sedimentary basin and whose denominator is the amount of oil and gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties in the Cook Inlet sedimentary basin;

(C) AS 38.05.180 (i), AS 41.09.010 , or AS 43.55.025 for an expenditure incurred for exploration outside the Cook Inlet sedimentary basin, zero;

(D) AS 43.55.024 (a), zero;

(2) outside the Cook Inlet sedimentary basin and used in the state is, for a credit under

(A) AS 43.55.024 (c), a fraction whose numerator is the amount of gas subject to AS 43.55.011 (o) in BTU equivalent barrels produced by the producer during the calendar year, and whose denominator is the total amount of oil and gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties in the state;

(B) AS 38.05.180 (i), AS 41.09.010 , or AS 43.55.025 for an expenditure incurred for exploration outside the Cook Inlet sedimentary basin and that is available to be applied for the calendar year of production, a fraction whose numerator is the amount of gas subject to AS 43.55.011 (o) in BTU equivalent barrels produced by the producer during the calendar year, and whose denominator is the amount of oil and gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties outside the Cook Inlet sedimentary basin;

(C) AS 38.05.180 (i), AS 41.09.010 , or AS 43.55.025 for an expenditure incurred for exploration in the Cook Inlet sedimentary basin, zero;

(D) AS 43.55.024 (a), a fraction whose numerator is the amount of gas subject to AS 43.55.011 (o) in BTU equivalent barrels produced by the producer during the calendar year from leases or properties no part of which is north of 68 degrees North latitude, and whose denominator is the amount of oil and gas taxable under AS 43.55.011 (e) in BTU equivalent barrels produced by the producer during the calendar year from all leases or properties outside the Cook Inlet sedimentary basin, no part of which is north of 68 degrees North latitude.

(b) Except for excess tax credits remaining after the accounting required under (c) of this section, a tax credit allocated under (a) of this section to gas produced from leases or properties

(1) in the Cook Inlet sedimentary basin

(A) may be applied, if at all, only against the tax levied by AS 43.55.011 (e) for that gas;

(B) to the extent not applied as described in (A) of this paragraph, is not available to be used as a tax credit in any manner and is considered lost;

(2) outside the Cook Inlet sedimentary basin and used in the state

(A) may be applied, if at all, only against the tax levied by AS 43.55.011 (e) for that gas;

(B) to the extent not applied as described in (A) of this paragraph, is not available to be used as a tax credit in any manner and is considered lost.

(c) For a calendar year for which a limitation under AS 43.55.011 (j), (k), or (o) on the tax levied by AS 43.55.011 (e) has the effect of reducing the producer's tax for oil or gas produced from one or more leases or properties below the amount of the tax that would be levied in the absence of that limitation, the producer shall account under (d) and (e) of this section for the tax credits that are allocated under (a) of this section to gas produced from leases or properties in the Cook Inlet sedimentary basin or to gas produced from leases or properties outside the Cook Inlet sedimentary basin and used in the state.

(d) A producer subject to (c) of this section shall calculate its excess tax credits under this subsection as follows:

(1) first, if the producer has a tax credit under AS 43.55.024 (a) whose portion allocated under (a)(2)(D) of this section is greater than zero, the producer shall compare that portion to the amount of tax levied by AS 43.55.011 (e), after application of any limitation under AS 43.55.011 (o), for gas produced from leases or properties outside the Cook Inlet sedimentary basin no part of which is north of 68 degrees North latitude and that is used in the state;

(2) second, if the producer has a tax credit under AS 43.55.024 (c) whose portion allocated under (a)(2)(A) of this section is greater than zero, the producer shall compare that portion to the amount of tax levied by AS 43.55.011 (e), after application of any limitation under AS 43.55.011 (o), for gas produced from leases or properties outside the Cook Inlet sedimentary basin and that is used in the state, and after further reducing that amount of tax, but not below zero, by the lesser of the two amounts, if any, compared in (1) of this subsection;

(3) third, if the producer has a tax credit under AS 43.55.024 (c) whose portion allocated under (a)(1)(A) of this section is greater than zero, the producer shall compare that portion to the amount of tax levied by AS 43.55.011 (e), after application of any limitation under AS 43.55.011 (j), for gas produced from leases or properties in the Cook Inlet sedimentary basin;

(4) fourth, if the producer has a tax credit under AS 43.55.025 whose portion allocated under (a)(2)(B) of this section is greater than zero, the producer shall compare that portion to the amount of tax levied by AS 43.55.011 (e), after application of any limitation under AS 43.55.011 (o), for gas produced from leases or properties outside the Cook Inlet sedimentary basin and that is used in the state, and after further reducing that amount of tax, but not below zero, by the sum of the lesser of the two amounts, if any, compared in (1) of this subsection and the lesser of the two amounts, if any, compared in (2) of this subsection;

(5) fifth, if the producer has a tax credit under AS 43.55.025 whose portion allocated under (a)(1)(B) of this section is greater than zero, the producer shall compare that portion to the amount of tax levied by AS 43.55.011 (e), after application of any limitation under AS 43.55.011 (j), for gas produced from leases or properties in the Cook Inlet sedimentary basin, and after further reducing that amount of tax, but not below zero, by the lesser of the two amounts, if any, compared in (3) of this subsection;

(6) sixth, if the producer has a tax credit under AS 41.09.010 whose portion allocated under (a)(2)(B) of this section is greater than zero, the producer shall compare that portion to the amount of tax levied by AS 43.55.011 (e), after application of any limitation under AS 43.55.011 (o), for gas produced from leases or properties outside the Cook Inlet sedimentary basin and that is used in the state, and after further reducing that amount of tax, but not below zero, by the sum of the lesser of the two amounts, if any, compared in (1) of this subsection, the lesser of the two amounts, if any, compared in (2) of this subsection, and the lesser of the two amounts, if any, compared in (4) of this subsection;

(7) seventh, if the producer has a tax credit under AS 41.09.010 whose portion allocated under (a)(1)(B) of this section is greater than zero, the producer shall compare that portion to the amount of tax levied by AS 43.55.011 (e), after application of any limitation under AS 43.55.011 (j), for gas produced from leases or properties in the Cook Inlet sedimentary basin, and after further reducing that amount of tax, but not below zero, by the sum of the lesser of the two amounts, if any, compared in (3) of this subsection and the lesser of the two amounts, if any, compared in (5) of this subsection;

(8) eighth, if the producer has a tax credit under AS 38.05.180 (i) whose portion allocated under (a)(2)(B) of this section is greater than zero, the producer shall compare that portion to the amount of tax levied by AS 43.55.011 (e), after application of any limitation under AS 43.55.011 (o), for gas produced from leases or properties outside the Cook Inlet sedimentary basin and that is used in the state, and after further reducing that amount of tax, but not below zero, by the sum of the lesser of the two amounts, if any, compared in (1) of this subsection, the lesser of the two amounts, if any, compared in (2) of this subsection, the lesser of the two amounts, if any, compared in (4) of this subsection, and the lesser of the two amounts, if any, compared in (6) of this subsection;

(9) ninth, if the producer has a tax credit under AS 38.05.180 (i) whose portion allocated under (a)(1)(B) of this section is greater than zero, the producer shall compare that portion to the amount of tax levied by AS 43.55.011 (e), after application of any limitation under AS 43.55.011 (j), for gas produced from leases or properties in the Cook Inlet sedimentary basin, and after further reducing that amount of tax, but not below zero, by the sum of the lesser of the two amounts, if any, compared in (3) of this subsection, the lesser of the two amounts, if any, compared in (5) of this subsection, and the lesser of the two amounts, if any, compared in (7) of this subsection;

(10) tenth, for each comparison made in (1) - (9) of this subsection, if the former amount exceeds the latter amount, the difference constitutes excess tax credits, and the producer's total amount of excess tax credits is the sum of the excess tax credits, if any, calculated for all comparisons.

(e) If a producer's total amount of excess tax credits calculated under (d) of this section is greater than zero, the producer shall

(1) for each lease or property for which a limitation under AS 43.55.011 (j), (k), or (o) on the tax levied by AS 43.55.011 (e) has the effect of reducing the producer's tax below the amount of tax that would be levied in the absence of that limitation, calculate the amount of that reduction;

(2) calculate the total of the reductions calculated under (1) of this subsection for all affected leases or properties;

(3) reduce the amount of excess tax credits by the following amount, as applicable, but not to less than zero:

(A) the total calculated under (2) of this subsection, unless the producer has excess adjusted lease expenditures for the calendar year that are accounted for under 15 AAC 55.224(b) ;

(B) if the producer has excess adjusted lease expenditures for the calendar year that are accounted for under 15 AAC 55.224(b) ,

(i) the remainder calculated by subtracting the amount calculated under 15 AAC 55.224(b) (2) from the amount calculated under 15 AAC 55.224(b)(4), if the former amount is less than the latter amount; or

(ii) zero, if the amount calculated under 15 AAC 55.224(b) (2) is greater than or equal to the amount calculated under 15 AAC 55.224(b) (4).

(f) Any amount of excess tax credits remaining after reduction under (e)(3) of this section may be used for a later calendar year, transferred to another person, or applied against a tax levied for oil or gas not subject to AS 43.55.011 (j), (k), or (o), to the extent allowed under the law applicable to those tax credits. The remaining amount of excess tax credits is treated as a credit under AS 43.55.025 to the extent, if any, that the producer correctly included a credit under AS 43.55.025 in determining excess tax credits, and the balance of the remaining amount of excess tax credits, if any, is first treated as a credit under AS 38.05.180 (i) or AS 41.09.010 to the extent, if any, that the producer correctly included a credit under AS 38.05.180 (i) or AS 41.09.010 in determining excess tax credits, and next as a credit under AS 43.55.024 (c) to the extent, if any, that the producer correctly included a credit under AS 43.55.024 (c) in determining excess tax credits, and finally as a credit under AS 43.55.024 (a) to the extent, if any, that the producer correctly included a credit under AS 43.55.024 (a) in determining excess tax credits.

(g) A tax credit under AS 38.05.180 (i), AS 41.09.010 , or AS 43.55.025 is subject to AS 43.55.011 (m) and (a) - (f) of this section if the person that originally qualified for the tax credit fails to transfer the tax credit to another person before or during the calendar year that the credit becomes available to be applied against a tax levied by AS 43.55.011 (e) for gas produced from leases or properties in the Cook Inlet sedimentary basin or for gas produced from leases or properties outside the Cook Inlet sedimentary basin and used in the state, as applicable. If the tax credit is transferred to another person before or during that calendar year, the transferee's use of the tax credit is not subject to AS 43.55.011 (m) or (a) - (f) of this section, irrespective of whether the transferee produces gas from a lease or property in the Cook Inlet sedimentary basin or gas from a lease or property outside the Cook Inlet sedimentary basin and that is used in the state. For purposes of this subsection, a tax credit under AS 43.55.025 is not available to be applied against a tax until the department has issued a production tax credit certificate for the credit under AS 43.55.025 (f)(5).

(h) At the request of the person seeking a production tax credit certificate under AS 43.55.025 (f), the department will defer issuing a certificate that is otherwise ready for issuance in December of a calendar year until January of the next calendar year.

(i) This section applies to oil and gas produced and expenditures incurred after June 30, 2007, and before January 1, 2022.

(j) The following example illustrates (a) - (f) of this section:

A producer produces oil or gas from three leases or properties, called Property A, Property B, and Property C. All three properties are located outside the Cook Inlet sedimentary basin; only Property A is located south of 68 degrees North latitude. In the calendar year in question, the producer's oil and gas production from the respective properties taxable under AS 43.55.011 (e) is as follows:

Property A: 1,000,000 BTU equivalent barrels of gas used in the state, with a volume of 5,649,718 Mcf and a tax under AS 43.55.011 (e) of $3,000,000, before application of the tax limitation under AS 43.55.011 (o); and 4,000,000 barrels of oil;

Property B: 5,000,000 BTU equivalent barrels of gas used in the state, with a volume of 28,248,587 Mcf and a tax under AS 43.55.011 (e) of $10,000,000, before application of the tax limitation under AS 43.55.011 (o); and 5,000,000 BTU equivalent barrels of gas not used in the state;

Property C: 10,000,000 barrels of oil.

For the calendar year in question, the producer qualifies for a tax credit under AS 43.55.024 (c) of up to $7,562,000, a tax credit under AS 43.55.025 of $50,000,000 for expenditures incurred outside the Cook Inlet sedimentary basin, and a tax credit under AS 43.55.024 (a) of up to $6,000,000.

Step One: Allocate the tax credits to gas produced from leases or properties outside the Cook Inlet sedimentary basin and used in the state:

Under (a)(2)(A) of this section, the allocated fraction of the tax credit under AS 43.55.024 (c) is 6,000,000 BTU equivalent barrels (the amount of gas subject to AS 43.55.011 (o)), divided by 25,000,000 BTU equivalent barrels (the total amount of taxable oil and gas produced from all leases or properties in the state), or 6/25. 6/25 * $7,562,000 = $1,815,000.

Under (a)(2)(B) of this section, the allocated fraction of the tax credit under AS 43.55.025 is 6,000,000 BTU equivalent barrels (the amount of gas subject to AS 43.55.011 (o)), divided by 25,000,000 BTU equivalent barrels (the amount of taxable oil and gas produced from all leases or properties outside the Cook Inlet sedimentary basin), or 6/25. 6/25 * $50,000,000 = $12,000,000.

Under (a)(2)(D) of this section, the allocated fraction of the tax credit under AS 43.55.024 (a) is 1,000,000 BTU equivalent barrels (the amount of gas subject to AS 43.55.011 (o) produced only from leases or properties south of 68 degrees North latitude), divided by 5,000,000 BTU equivalent barrels (the amount of taxable oil and gas produced from all leases or properties outside the Cook Inlet sedimentary basin and south of 68 degrees North latitude), or 1/5. 1/5 * $6,000,000 = $1,200,000.

Step Two: Calculate excess tax credits:

Under (d) of this section, first the allocated portion of the tax credit under AS 43.55.024 (a), $1,200,000, is compared to the tax for the gas used in the state and produced outside the Cook Inlet sedimentary basin and south of 68 degrees North latitude, after application of the tax limitation under AS 43.55.011 (o). With that limitation applied as set out in 15 AAC 55.440(d) , the tax is 5,649,718 Mcf multiplied by $.177 per Mcf, or $1,000,000, which is also the actual tax, since it is less than the tax would be without the limitation. The allocated portion of the tax credit exceeds the tax by $200,000, which is excess tax credits.

Second, the allocated portion of the tax credit under AS 43.55.024 (c), $1,815,000, is compared to the tax for the gas used in the state and produced anywhere outside the Cook Inlet sedimentary basin, after application of the tax limitation under AS 43.55.011 (o), and after further reduction by the $1,000,000 in tax credit assumed, in accordance with (b)(2) of this section, to be used in the first comparison. With that limitation applied as set out in 15 AAC 55.440(d) , the tax is 33,898,305 Mcf multiplied by $.177 per Mcf, or $6,000,000, which is also the actual tax, since it is less than the tax would be without the limitation. After subtracting the $1,000,000 from the first comparison, the amount to be compared to the allocated portion of the tax credit is $5,000,000. Because the allocated portion of the tax credit is less than $5,000,000, no excess tax credits are associated with the tax credit under AS 43.55.024 (c).

Third, the allocated portion of the tax credit under AS 43.55.025 , $12,000,000, is compared to the tax after application of the tax limitation as used in the second comparison, after reduction as in the second comparison, and after further reduction by the $1,815,000 tax credit assumed to be used in the second comparison. Therefore, the amount to be compared to the allocated portion of the tax credit is $6,000,000 minus $1,000,000 minus $1,815,000, or $3,185,000. The allocated portion of the tax credit exceeds that amount by $8,815,000 which is excess tax credits.

The total excess tax credits are therefore $200,000 plus $8,815,000, or $9,015,000.

Step Three: Calculate tax reductions resulting from the tax limitation under AS 43.55.011 (o):

Under (e)(1) of this section, the tax reduction for Property A is calculated by subtracting the tax after application of the tax limitation under AS 43.55.011 (o), $1,000,000, from the tax as calculated without that limitation, $3,000,000, for a reduction of $2,000,000. The tax reduction for Property B is calculated by first calculating the tax with the limitation applied as set out in 15 AAC 55.440(d) , $.177 per Mcf multiplied by 28,248,587 Mcf, or $5,000,000, and subtracting that amount from the tax as calculated without that limitation, $10,000,000, for a reduction of $5,000,000.

Under (e)(2) of this section, the total of the tax reductions is $2,000,000 plus $5,000,000, or $7,000,000.

Step Four: Reduce excess tax credits under (e)(3) of this section:

In this example the producer does not have any lease expenditures accounted for under 15 AAC 55.224(b) . Therefore, the total excess tax credits calculated in Step Two, $9,015,000, are reduced by the total of the tax reductions calculated in Step Three, $7,000,000. The amount of remaining excess tax credits is $2,015,000.

Step Five: Classify remaining excess tax credits under (f) of this section:

The $2,015,000 in remaining excess tax credits is compared to the allocated portion of the tax credit under AS 43.55.025 , $12,000,000. Since $2,015,000 is less than $12,000,000, the entire amount of remaining excess tax credits is treated as a tax credit under AS 43.55.025 .

History: Eff. 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.024

AS 43.55.025

AS 43.55.110

15 AAC 55.345. Procedures for applying certain tax credits

(a) To apply a tax credit allowed under AS 43.55.023 or 43.55.024 against a tax liability under AS 43.55.011 , a producer must file, no later than March 31 of the year following the calendar year for which the tax was levied, a claim for the tax credit in the statement described in AS 43.55.030 (a), setting out the information required by the department on a form prescribed by the department as part of that statement.

(b) In addition to other information required by the department, a claim under this section for a tax credit for a qualified capital expenditure under AS 43.55.023 (a) or carried-forward annual loss under AS 43.55.023 (b) must include

(1) a description and accounting of the expenditures for which the credit is claimed, including a summary of the types of expenditures and the month and calendar year each expenditure was incurred;

(2) a description of the lease or property or other land where the exploration, development, or production activities with respect to which the relevant expenditures were incurred took place, and if the producer is not the operator, identification of the operator;

(3) a list of any partners or other entities that shared in costs of which the relevant expenditures incurred by the producer are the producer's share, providing the respective shares of the partners or other entities, including the producer, and identifying the operator of the venture;

(4) identification of the custodians of the accounting records for the relevant expenditures, including the general ledgers, contracts, progress billings and invoices, and joint interest billings;

(5) if applicable, the producer's written

(A) agreement required under AS 43.55.023 (a)(2), as the provisions of that paragraph read on June 30, 2007, in the case of an expenditure incurred for exploration work performed before July 1, 2008;

(B) agreements required under AS 43.55.023 (a)(2), as amended by sec. 25, ch. 1, SSSLA 2007, and documentation that the producer has submitted to the Department of Natural Resources all data referred to in AS 43.55.023 (a)(2)(B), as amended by sec. 25, ch. 1, SSSLA 2007, in the case of an expenditure incurred for exploration work performed after June 30, 2008; and

(6) in the case of a qualified capital expenditure, the producer's certification that a tax credit has not been and is not being taken for the expenditure under AS 38.05.180 (i), AS 41.09.010 , AS 43.20.043 , or AS 43.55.025 , except as provided under (c) of this section.

(c) A producer that files an application under 15 AAC 55.355 for an alternative oil and gas exploration tax credit under AS 43.55.025 for an expenditure that the producer believes is a qualified capital expenditure may file a contingent claim under this section for a qualified capital expenditure tax credit under AS 43.55.023 (a), if and to the extent that the expenditure later is determined not to qualify for a tax credit under AS 43.55.025 but is determined to qualify for a tax credit under AS 43.55.023 (a).

(d) In addition to other information required by the department, a claim under this section for a tax credit shown on a transferable tax credit certificate under AS 43.55.023 (e) must

(1) identify the certificate and the person that transferred the certificate to the producer claiming the tax credit; and

(2) state the percentage, if any, of the tax credit that was subtracted in calculating the amount of an installment payment for each month under 15 AAC 55.380(b) or 15 AAC 55.381(b) , as applicable.

(e) In addition to other information required by the department, a claim under this section for a tax credit for a transitional investment expenditure under AS 43.55.023 (i)(2) must include the producer's certification that a tax credit has not been and is not being taken under AS 38.05.180 (i), AS 41.09.010 , AS 43.20.043 , or AS 43.55.025 for the expenditure.

(f) A producer claiming a tax credit under AS 43.55.023 (i)(2) for calendar year 2006 need not provide documentation of the person's transitional investment expenditures other than a certification that the producer incurred sufficient transitional investment expenditures to qualify for the amount of the tax credit claimed. Nothing in this subsection limits the department's right to require additional documentation on later audit.

(g) A producer that has incurred transitional investment expenditures and that wishes to take a tax credit under AS 43.55.023 (i)(2) for a calendar year after 2006 must provide to the department no later than March 31, 2008, in addition to other information the department may require, a complete statement of the producer's transitional investment expenditures, by calendar year in which the expenditure was incurred and by lease or property to which the expenditure related, and showing the producer's total amount of transitional investment expenditures.

(h) A producer that files a claim for a tax credit under this section shall retain and make available to the department upon request all financial and technical source records supporting the credit claimed. If the credit claimed relates to an exploration well or to geological or geophysical exploration, the records to be retained and made available must include drill rig logs, daily drilling logs, and activity logs.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.024

AS 43.55.025

AS 43.55.030

AS 43.55.040

AS 43.55.110

15 AAC 55.350. Alternative tax credit for exploration expenditures for work performed after June 30, 2003, and before July 1, 2008.

(a) An explorer may request an alternative oil and gas exploration tax credit under AS 43.55.025 , as the provisions of that section read on June 30, 2008, by filing an application with the department no later than six months after the completion date of the exploration activity for which the tax credit is claimed. For a tax credit that the applicant wishes to use for a previous calendar year, as provided under 15 AAC 55.370(c) , an application may be filed with the statement filed under AS 43.55.030 (a) for that calendar year.

(b) For a particular exploration well, an explorer may claim a tax credit of

(1) 20 percent of exploration expenditures,

(A) if those expenditures qualify under AS 43.55.025 (b) and (c), as the provisions of those subsections read on June 30, 2008; and

(B) regardless of whether the well is less than 25 miles from an existing unit that is under a plan of development;

(2) 20 percent of exploration expenditures,

(A) if those expenditures qualify under AS 43.55.025 (b) and (d), as the provisions of those subsections read on June 30, 2008; and

(B) regardless of whether the bottom hole of the exploration well is less than three miles away from the bottom hole of a preexisting suspended, completed, or abandoned oil or gas well, as the term "preexisting" was defined in AS 43.55.025 (c)(2)(A) on June 30, 2008; or

(3) 40 percent of exploration expenditures, if those expenditures qualify under AS 43.55.025 (b), (c), and (d), as the provisions of those subsections read on June 30, 2008.

(c) For a particular seismic or geophysical exploration activity, an explorer may claim a tax credit of 40 percent of exploration expenditures, if those expenditures qualify under AS 43.55.025 (b) and (e), as the provisions of those subsections read on June 30, 2008.

(d) This section applies to exploration expenditures for work performed after June 30, 2003, and before July 1, 2008.

History: Eff. 5/3/2007, Register 182; am 12/25/2009, Register 192

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

Editor's note: The subject matter of 15 AAC 55.350 was formerly located at 15 AAC 55.220. The history note for 15 AAC 55.350 does not reflect the history of the earlier section.

15 AAC 55.351. Alternative tax credit for exploration expenditures for work performed after June 30, 2008, and for certain seismic exploration work performed before July 1, 2003.

(a) An explorer may request an alternative oil and gas exploration tax credit under AS 43.55.025 by filing an application with the department (1) no later than six months after completion of the exploration activity for which the tax credit is claimed; or (2) in the case of seismic exploration performed before July 1, 2003, at any time before January 1, 2016.

For a tax credit that the applicant wishes to use for a previous calendar year, as provided under 15 AAC 55.370(c) , an application may be filed with the statement filed under AS 43.55.030 (a) for that calendar year.

(b) For purposes of AS 43.55.025 (c)(2)(B), the distance between the bottom hole locations of two wells is measured as the horizontal distance between the surface location directly above the bottom hole location of each well.

(c) For purposes of AS 43.55.025 (d)(2), the distance between an exploration well and the outer boundary of a unit is measured as the horizontal distance between the surface location directly above the bottom hole location of the well and the nearest point on the outer boundary of the unit.

(d) This section applies to exploration expenditures for work performed after June 30, 2008 and before July 1, 2016, and to seismic exploration expenditures for work performed before July 1, 2003.

History: Eff. 12/25/2009, Register 192

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

15 AAC 55.355. Alternative oil and gas exploration tax credit claim for expenditures for work performed after June 30, 2003, and before July 1, 2008.

(a) An application for an alternative oil and gas exploration tax credit under AS 43.55.025 , as the provisions of that section read on June 30, 2008, for a particular exploration activity may, on a form provided by the department, be filed by

(1) a single explorer that

(A) holds the entire interest in the particular well or seismic or geophysical exploration activity; and

(B) incurred 100 percent of the expenditures for which the credit is claimed; or

(2) a designated joint applicant that is authorized in a writing, signed by each explorer that incurred expenditures, to file a joint tax credit application on behalf of all those explorers; a joint application must be for the total qualified expenditures incurred by all the explorers for the exploration activity for which the credit is claimed and must include a copy of the written authorization signed by each explorer.

(b) A tax credit application for an exploration well must include the following information:

(1) the applicant's name, permanent contact address, and telephone number;

(2) if the applicant is a designated joint applicant, under (a)(2) of this section, the name and address of each explorer represented in the application and the percentage of the total qualified exploration expenditures incurred by each explorer;

(3) a description of the exploration activities for which the credit is claimed;

(4) an accounting of the qualified exploration expenditures for which credit is claimed;

(5) the date the exploration well was spudded, the date it was drilled, and the completion date;

(6) the bottom hole location and the surface location of the exploration well;

(7) for an application under AS 43.55.025 (b) and (c), as the provisions of those subsections read on June 30, 2008, the

(A) bottom hole location of the nearest preexisting well, as the term "preexisting" was defined in AS 43.55.025 (c)(2)(A) on June 30, 2008, or for a well that explores a Cook Inlet prospect, a showing that the well constitutes a distinct separate exploration target;

(B) date the nearest preexisting well was drilled, as the term "preexisting" was defined in AS 43.55.025 (c)(2)(A) on June 30, 2008;

(C) completion date of the nearest preexisting well, as the term "preexisting" was defined in AS 43.55.025 (c)(2)(A) on June 30, 2008; and

(D) the distance between the bottom hole location of the exploration well and the bottom hole location of the nearest preexisting well, as the term "preexisting" was defined in AS 43.55.025 (c)(2)(A) on June 30, 2008, measured as a horizontal distance between the surface location directly above the bottom hole location of each well;

(8) if the exploration well is within a unit boundary,

(A) identification of the unit; and

(B) a copy of the plan of exploration or plan of development that was in effect for the unit on May 13, 2003;

(9) for an application under AS 43.55.025 (b) and (d), as the provisions of those subsections read on June 30, 2008,

(A) identification of the nearest unit that is under a plan of development; and

(B) the distance between the bottom hole location of the exploration well and the outer boundary of the nearest unit that is under a plan of development,

(i) as the boundary was delineated on July 1, 2003; and

(ii) measured as a horizontal distance between the surface location directly above the bottom hole location of the well and the nearest point on the outer boundary of the unit;

(10) a survey plat that graphically identifies all the locations, distances, and dates required under this subsection;

(11) a copy of the Well Completion or Recompletion Report and Log (Form 10-407) for the exploration well filed with the Alaska Oil and Gas Conservation Commission under 20

AAC 25.070, or a copy of a well completion report that is substantially similar to that filing and that is filed with a federal agency; in addition, if the application is for expenditures that qualify under AS 43.55.025 (c)(2), as the provisions of that paragraph read on June 30, 2008, the application must include a copy of the Well Completion or Recompletion Report and Log (Form 10-407) for the nearest preexisting well, as the term "preexisting" was defined in AS 43.55.025 (c)(2)(A) on June 30, 2008, or the substantially similar federal filing;

(12) the written agreements required under AS 43.55.025 (f)(2), as the provisions of that paragraph read on June 30, 2008;

(13) other information requested by the department, as the department considers necessary for reviewing the application.

(c) A tax credit application for a particular seismic or geophysical exploration activity must include the following information:

(1) the name, permanent contact address, and telephone number of the applicant;

(2) if the applicant is a designated joint applicant, under (a)(2) of this section, the name and address of each explorer represented in the application and the percentage of the total qualified exploration expenditures incurred by each explorer;

(3) a description of the seismic or geophysical exploration activities for which the credit is claimed;

(4) an accounting of the qualified exploration expenditures for which credit is claimed;

(5) the date of and location where the seismic or geophysical activity occurred;

(6) a statement verifying

(A) that the seismic or geophysical exploration activities occurred outside of the boundaries of a unit that is under a plan of exploration or a plan of development; or

(B) the percentage of the seismic or geophysical exploration activities that occurred inside the unit boundary, if a portion of those activities crossed into the boundary of a unit;

(7) the written agreements required under AS 43.55.025 (f)(2), as the provisions of that paragraph read on June 30, 2008;

(8) other information requested by the department, as the department considers necessary for reviewing the application.

(d) An applicant under this section shall retain, and make available to the department upon request, all financial and technical source documents and records supporting the credit claimed for an exploration well or seismic or geophysical exploration activities, including the rig logs, daily drilling logs, and activity logs.

(e) After the six-month application period in AS 43.55.025 (f) has expired, the department will issue one or more production tax credit certificates for the qualified expenditures allowed under AS 43.55.025 .

(f) The department may allocate claimed expenditures between exploration and non-exploration activities, and will deny a claimed exploration expenditure that it determines not to be reasonably required or not incurred for qualified exploration activities.

(g) This section applies to exploration expenditures for work performed after June 30, 2003, and before July 1, 2008.

History: Eff. 5/3/2007, Register 182; am 12/25/2009, Register 192

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

Editor's note: The subject matter of 15 AAC 55.355 was formerly located at 15 AAC 55.225. The history note for 15 AAC 55.355 does not reflect the history of the earlier section.

15 AAC 55.356. Alternative oil and gas exploration tax credit claim for expenditures for work performed after June 30, 2008, and for certain seismic exploration work performed before July 1, 2003.

(a) An application for an alternative oil and gas exploration tax credit under AS 43.55.025 for a particular exploration activity may, on a form provided by the department, be filed by

(1) a single explorer that

(A) holds the entire interest in the particular well or seismic or other geophysical exploration activity; and

(B) incurred 100 percent of the expenditures for which the credit is claimed; or

(2) a designated joint applicant that is authorized in a writing, signed by each explorer that incurred expenditures, to file a joint tax credit application on behalf of all those explorers; a joint application must be for the total qualified expenditures incurred by all the explorers for the exploration activity for which the credit is claimed and must include a copy of the written authorization signed by each explorer.

(b) An application for a tax credit for an exploration well must include the following information:

(1) the applicant's name, permanent contact address, and telephone number;

(2) if the applicant is a designated joint applicant, under (a)(2) of this section, the name and address of each explorer represented in the application and the percentage of the total qualified exploration expenditures incurred by each explorer;

(3) a description of the exploration activities for which the credit is claimed;

(4) an accounting of the qualified exploration expenditures for which credit is claimed;

(5) the date the exploration well was spudded, the dates drilling occurred, and the date the well was completed, suspended, or abandoned as reported to the Alaska Oil and Gas Conservation Commission under 20 AAC 25.070;

(6) the bottom hole location and the surface location of the exploration well;

(7) for an application for a tax credit requiring qualification under AS 43.55.025 (b) and (c),

(A) the determination of the commissioner of natural resources under

(i) AS 43.55.025 (c)(2)(A)(iii) that the geological objective of the well is a potential oil or gas trap that is distinctly separate from any trap that has been tested by a preexisting well; and

(ii) AS 43.55.025 (c)(2)(C) that the well was consistent with achieving the explorer's stated geological objective; if the determination is not available before the application deadline under 15 AAC 55.351(a) , it may instead be submitted as a later supplement to the filed application; and

(B) for a well other than a well to explore a Cook Inlet prospect, the spud date and bottom hole location of the nearest preexisting well and the distance between the bottom hole location of the exploration well and the bottom hole location of the nearest preexisting well;

(8) if the exploration well is within a unit boundary,

(A) identification of the unit; and

(B) if a plan of exploration or plan of development was in effect for the unit before May 14, 2003, a copy of the plan;

(9) for an application for a tax credit requiring qualification under AS 43.55.025 (b) and (d),

(A) identification of the nearest unit that is under a plan of development; and

(B) the distance between the bottom hole location of the exploration well and the outer boundary of the nearest unit that is under a plan of development, as the boundary was delineated on July 1, 2003;

(10) a survey plat that graphically identifies all the locations, distances, and dates required to be reported under this subsection;

(11) a copy of the Well Completion or Recompletion Report and Log (Form 10-407) for the exploration well filed with the Alaska Oil and Gas Conservation Commission under 20 AAC 25.070, or a copy of a well completion report that is substantially similar to that filing and that is filed with a federal agency; in addition, if the application is for expenditures that qualify under AS 43.55.025 (c), the application must include a copy of the Well Completion or Recompletion Report and Log (Form 10-407) for the nearest preexisting well, or the substantially similar federal filing;

(12) the written agreements required under AS 43.55.025 (f)(2);

(13) other information requested by the department, as the department considers necessary for reviewing the application.

(c) An application for a tax credit requiring qualification under AS 43.55.025 (b) and (e) or under AS 43.55.025 (k) for a particular seismic or other geophysical exploration activity must include the following information:

(1) the name, permanent contact address, and telephone number of the applicant;

(2) if the applicant is a designated joint applicant, under (a)(2) of this section, the name and address of each explorer represented in the application and the percentage of the total qualified exploration expenditures incurred by each explorer;

(3) a description of the seismic or other geophysical exploration activities for which the credit is claimed;

(4) an accounting of the qualified exploration expenditures for which credit is claimed;

(5) the date and location where the seismic or other geophysical activity occurred;

(6) a statement verifying

(A) that the seismic or other geophysical exploration activities occurred outside of the boundaries of a unit that is under a plan of exploration or a plan of development or, in the case of seismic exploration under AS 43.55.025 (k), outside of the boundaries of a production unit; or

(B) the percentage of the seismic or other geophysical exploration activities that occurred inside the unit boundary, if a portion of those activities crossed into the boundary of a unit;

(7) the written agreements required under AS 43.55.025 (f)(2);

(8) in the case of seismic exploration under AS 43.55.025 (k), a written statement from the Department of Natural Resources that the commissioner of natural resources considers acquiring the seismic exploration data for public distribution to be in the best interest of the state;

(9) other information requested by the department, as the department considers necessary for reviewing the application.

(d) An applicant under this section shall retain, and make available to the department upon request, all financial and technical source documents and records supporting the credit claimed for an exploration well or seismic or other geophysical exploration activities, including the rig logs, daily drilling logs, and activity logs.

(e) If the department determines that all data required to be submitted to the Department of Natural Resources under AS 43.55.025 have been submitted, and, except for a credit under AS 43.55.025 (k), after the six-month application period in AS 43.55.025 (f) has expired, the department will issue one or more production tax credit certificates for the qualified expenditures allowed under AS 43.55.025 .

(f) The department may allocate claimed expenditures between exploration and non-exploration activities, and will deny a claimed exploration expenditure that it determines not to be reasonably required or not incurred for qualified exploration activities.

(g) This section applies to exploration expenditures for work performed after June 30, 2008 and before July 1, 2016, and to seismic exploration expenditures under AS 43.55.025 (k) for work performed before July 1, 2003.

History: Eff. 12/25/2009, Register 192

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

15 AAC 55.360. Qualified exploration expenditures

(a) For purposes of the alternative oil and gas exploration tax credit under

(1) AS 43.55.025 , as the provisions of that section read on June 30, 2008, qualified exploration expenditures are the reasonably required direct costs for work performed on a particular exploration well or seismic or geophysical exploration project on or after July 1, 2003 and before July 1, 2008;

(2) AS 43.55.025 , in effect on July 1, 2008, qualified exploration expenditures are the reasonably required direct costs for work performed on a particular exploration well or seismic or other geophysical exploration project after June 30, 2008, and before July 1, 2016, or on a particular seismic exploration project before July 1, 2003.

(b) Qualified exploration expenditures for an exploration well include costs incurred for

(1) surveying and preparing the exploration well drill site;

(2) constructing new ice or gravel roads, from the terminus of an existing ice or gravel road used in oil or gas operations to the exploration well site, and building and maintaining docks, helipads, or landing areas necessary to the exploratory drilling activity; costs for these activities are calculated as follows:

(A) for a road, dock, helipad, or landing area, the cost is the actual cost incurred;

(B) if the road, dock, helipad, or landing area is used for any activity other than the exploration activity for which the credit is claimed, the cost is allocated among the different activities based on the number of hours or days, as appropriate, that it is used for each activity, divided by the total number of hours or days it is used for all activities;

(3) in-state travel, temporary living quarters, and subsistence at or near the exploration well site for drilling crew and personnel engaged in onsite exploration activities;

(4) drilling rig costs, including

(A) transportation and preparation, including the costs of moving the drilling rig to the exploration well site, mobilization, rigging-up, de-mobilization, and rigging-down of the drilling rig on the exploration well site;

(B) onsite costs for operating the drilling rig, including onsite coring and well logging; onsite drilling rig operating costs are calculated as follows:

(i) if the drilling rig is under a third-party contract, the costs are calculated at the contractual operating rate;

(ii) if the drilling rig is owned wholly or partly by an explorer, the costs are calculated on the basis of the net book value of the rig on the date it arrives on the exploration well site; if the exploration well drilling activities are the first use of a drilling rig after it is transported into the state, the cost of transporting the drilling rig to the state and to the area-wide dock is added to the net book value of the drilling rig;

(iii) drilling rig operating costs may be claimed from the date the drilling rig arrives on the exploration well site until the earliest of the completion date, the date the drilling rig is released from the drilling operation, or the date the drilling rig moves off the exploration well site; if drilling activities are suspended for any reason for 15 consecutive calendar days, drilling rig operating costs are not allowed under this subparagraph for those 15 days or for any subsequent day until drilling activities are resumed; and

(C) drilling materials, supplies, maintenance, repairs, drilling crew labor, and drilling waste handling;

(5) transportation equipment used for drilling crews; the cost of transportation equipment is calculated as follows:

(A) if the equipment is under a third-party contract, the cost is calculated at the hourly or daily contract rate, as appropriate, multiplied by the number of hours or days the equipment is actually used for the exploration activity for which the credit is claimed, divided by the number of hours or days the equipment was available by contract for use in the exploration activity;

(B) if the equipment is owned wholly or partly by an explorer, the cost is calculated on the basis of the net book value of the equipment multiplied by the number of days or hours, as appropriate, the equipment is used in the exploration activity for which the credit is claimed, divided by the number of days or hours of estimated remaining useful life of the equipment;

(C) if the equipment is used for any activity other than the exploration activity for which the credit is claimed, the cost is allocated among the different activities based on the number of hours or days, as appropriate, it is used for each activity, divided by the total number of hours or days it is used for all activities; and

(6) communications expenses necessary to the exploration well.

(c) Qualified exploration expenditures for seismic and geophysical exploration include costs incurred for

(1) seismic exploration activities, initial processing of data derived from seismic exploration activities, and downhole geophysical surveys associated with well logging;

(2) in-state travel, temporary living quarters, and subsistence at or near the exploration site for seismic crew and other personnel engaged in the exploration activities;

(3) the seismic exploration crew; seismic exploration crew costs are calculated as follows:

(A) if the crew is provided under a third-party contract, at the rate provided in the contract;

(B) if the crew is provided by an explorer, as actual payments to the crew for time expended on the seismic activity;

(4) goods, services, and materials; costs for goods, services, and materials are calculated as follows:

(A) if goods, services, and materials are provided under a third-party contract, the costs are calculated at the contract rate;

(B) if goods, services, and materials are provided in whole or in part by an explorer, the costs are the actual costs incurred;

(C) if a good, service, or material is used for any activity other than the exploration activity for which the credit is claimed, the cost is allocated among the different activities based on the number of hours or days, as appropriate, it is used for each activity, divided by the total number of hours or days it is used for all activities; and

(5) seismic and geophysical equipment, off-site computers, and other modeling equipment used in the initial seismic data processing; the cost of that equipment, including maintenance and repairs, is calculated as follows:

(A) if the equipment is under a third-party contract, the cost is calculated at the hourly or daily contract rate multiplied by the number of hours or days, as appropriate, that the equipment is actually used for the exploration activity for which the credit is claimed, divided by the number of hours or days the equipment was available by contract for use in the exploration activity;

(B) if the equipment is owned wholly or partly by an explorer, the cost is calculated on the basis of the net book value of the equipment multiplied by the number of days or hours, as appropriate, the equipment is used in the exploration activity for which the credit is claimed, divided by the number of days or hours of estimated remaining useful life of the equipment;

(C) if the equipment is used for any activity other than the exploration activity for which the credit is claimed, the cost is allocated among the different activities based on the number of hours or days, as appropriate, it is used for each activity, divided by the total number of hours or days it is used for all activities.

(d) Qualified exploration expenditures for work performed after June 30, 2003 and before July 1, 2008, do not include costs that are disallowed under AS 43.55.025 (b)(3) or (4), as the provisions of those paragraphs read on June 30, 2008. Qualified exploration expenditures for work performed after June 30, 2008, do not include costs that are disallowed under AS 43.55.025 (b)(3) or (4), in effect on July 1, 2008. Qualified exploration expenditures for seismic exploration work performed before July 1, 2003, do not include costs that are disallowed under AS 43.55.025 (b)(3), in effect on July 1, 2008. For purposes of this subsection and

(1) AS 43.55.025 (b)(3), as the provisions of that paragraph read on June 30, 2008, "testing, stimulation, or completion costs" means costs incurred on the exploration site after discovery of oil or gas potential at the site, including costs incurred to prepare an exploration well for, or convert it to production, to prepare or monitor an exploration well for status as a producer or potential producer, or to conduct flow tests; in this paragraph, "discovery of oil or gas potential" means drilling an exploration well into a formation capable of producing previously undiscovered oil or gas reserves;

(2) AS 43.55.025 (b)(3), as the provisions of that paragraph read on June 30, 2008, and as those provisions are in effect on July 1, 2008,

(A) "administration, supervision, engineering, or lease operating costs" means overhead costs incurred for activities that

(i) do not occur on the exploration site; and

(ii) are not directly related to drilling an exploration well or conducting seismic exploration, including geophysical surveys other than seismic surveys;

(B) "geological or management costs" means costs incurred before drilling begins to determine or select possible exploration targets; "geological or management costs" includes airborne gravity and magnetic surveys;

(C) "community relations or environmental costs" includes costs incurred for environmental compliance programs required as a result of an environmental incident, spill, or disaster;

(D) "indirect or financing costs" includes

(i) bottom hole and dry hole contributions, and reimbursements and fees assessed for late participation; and

(ii) seismic or geophysical data purchased from another person.

(e) In this section,

(1) "labor costs" means the actual costs of labor, including the amount of customary or required benefits;

(2) "net book value" means, under generally accepted accounting principles, the dollar amount the owner of an asset records in its financial statement as the historical cost of the asset, excluding capitalized interest and net of accumulated depreciation or amortization.

(f) Qualified exploration expenditures for work performed on an exploration well after June 30, 2008, in the case of

(1) testing or stimulation costs, are limited to costs incurred to conduct activities necessary to appraise the well for its oil or gas production potential; those costs must be incurred before the well is suspended or abandoned;

(2) completion costs,

(A) are limited to costs incurred to equip and condition the well for the purpose of conducting activities described in (1) of this subsection;

(B) do not include expenditures to abandon or suspend a well; this subparagraph does not affect the treatment as qualified exploration expenditures of expenses required for abandonment of a dry hole within 18 months after the date the well was spudded as provided in AS 43.55.025 (b)(2)(D).

History: Eff. 5/3/2007, Register 182; am 12/25/2009, Register 192

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

Editor's note: The subject matter of 15 AAC 55.360 was formerly located at 15 AAC 55.230. The history note for 15 AAC 55.360 does not reflect the history of the earlier section.

15 AAC 55.365. Transfer of a transferable tax credit certificate or production tax credit certificate

(a) A person may transfer an interest in a transferable tax credit certificate issued under AS 43.55.023 (d) or a production tax credit certificate issued under AS 43.55.025 by notifying the department, on a transfer form provided by the department. A transfer form must include the following information:

(1) the names, federal tax identification numbers, and addresses of the transferor and the transferee;

(2) the amount of tax credit that was transferred, the nature of the transfer, and the monetary or other value received.

(b) Transfer of a tax credit certificate is effective on the date the department sends notice to the transferor that the certificate has been transferred.

(c) After a person has notified the department of a transfer under (a) of this section, the person may not use or transfer any additional interest in the tax credit certificate until the effective date of the transfer under (b) of this section.

(d) In this section, "transfer" means to sell, assign, exchange, or convey in any manner an interest in a tax credit certificate, regardless of whether compensation is received.

History: Eff. 5/3/2007, Register 182

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.025

AS 43.55.110

Editor's note: The subject matter of 15 AAC 55.365 was formerly located at 15 AAC 55.235. The history note for 15 AAC 55.365 does not reflect the history of the earlier section.

15 AAC 55.370. Applying production tax credit certificates against production tax liability

(a) To apply a production tax credit certificate issued under AS 43.55.025 against a production tax liability under AS 43.55.011 (e) or, for oil and gas produced before July 1, 2007, AS 43.55.011 (f), a producer must submit to the department, with the statement described in AS 43.55.030 (a), a written designation, on a form prescribed by the department, stating the

(1) amount of tax credit to be applied against the tax liability;

(2) calendar year for which the tax credit is to be applied; and

(3) percentage, if any, of the tax credit that was subtracted in calculating the amount of an installment payment for each month under 15 AAC 55.380(b) or 15 AAC 55.381(b) , as applicable.

(b) On receipt of a written designation under (a) of this section, subject to the provisions of 15 AAC 55.340 or 15 AAC 55.341, as applicable, the department will apply the designated tax credit against the producer's production tax liability under AS 43.55.011 (e) or, for oil and gas produced before July 1, 2007, AS 43.55.011 (f), as applicable, for the designated calendar year in the order listed under 15 AAC 55.375 or, if the producer submits a schedule under 15 AAC 55.375(c) , in the order listed in that schedule. Subject to the provisions of 15 AAC 55.340 or 15 AAC 55.341, as applicable, an unused amount of a tax credit designated for a calendar year under (a) of this section will be applied as a credit for the next calendar year for which the producer has a tax liability under AS 43.55.011 (e) or, for oil and gas produced before July 1, 2007, AS 43.55.011 (f), in the order listed under 15 AAC 55.375 or listed in the producer's then-current schedule.

(c) Except for a tax credit based on an expenditure for seismic exploration under AS 43.55.025 (k),

(1) the earliest calendar year for which a production tax credit under AS 43.55.025 may be applied against the tax liability of the producer that incurred the exploration expenditure on which the tax credit is based is the calendar year in which the exploration expenditure was incurred;

(2) subject to the department's later issuance of a production tax credit certificate covering the amount of the tax credit, the producer may apply the tax credit before the certificate is issued.

(d) The earliest calendar year for which a production tax credit under AS 43.55.025

(1) that is based on an expenditure for seismic exploration under AS 43.55.025 (k) may be applied against the tax liability of the producer that incurred the expenditure is the calendar year in which the production tax credit certificate is issued;

(2) may be applied against the tax liability of a transferee of the production tax certificate is the calendar year in which the effective date of the transfer of the certificate occurs.

(e) A production tax credit certificate does not accrue interest, and except for application against a production tax liability as provided in this section, may not be used in payment of any tax or other amount owed.

History: Eff. 5/3/2007, Register 182; am 12/25/2009, Register 192

Authority: AS 43.05.080

AS 43.55.025

AS 43.55.110

Editor's note: The subject matter of 15 AAC 55.370 was formerly located at 15 AAC 55.240. The history note for 15 AAC 55.370 does not reflect the history of the earlier section.

15 AAC 55.375. Order of applying tax credits

(a) For purposes of applying a percentage limitation under AS 43.55.023 (e) or 38.05.180(i) on the use of tax credits against a tax levied by AS 43.55.011 (e), a producer shall

(1) first, apply all tax credits allowable against the tax levied by AS 43.55.011 (e) other than credits subject to a percentage limitation under AS 43.55.023 (e) or 38.05.180(i);

(2) second, apply a credit subject to the percentage limitation under AS 38.05.180 (i) against not more than 50 percent of the remaining tax liability under AS 43.55.011 (e), if any;

(3) third, apply a credit subject to a percentage limitation under AS 43.55.023 (e) against not more than 20 percent of the balance of the remaining tax liability under AS 43.55.011 (e), if any.

(b) For purposes of applying a percentage limitation under AS 38.05.180 (i) on the use of tax credits against the minimum tax for oil and gas produced before July 1, 2007, from leases or properties in the state north of 68 degrees North latitude determined under AS 43.55.011 (f), as the provisions of that subsection read on June 30, 2007, a producer shall

(1) first, apply all tax credits allowable under AS 43.55.024 (c) and 43.55.025 against that minimum tax liability;

(2) second, apply a credit subject to the percentage limitation under AS 38.05.180 (i) against not more than 50 percent of the remaining minimum tax liability, if any.

(c) Except as provided under (a) and (b) of this section, a producer may apply tax credits in any order, if the producer submits with the statement required under AS 43.55.030 (a) a separate schedule setting out the order in which the tax credits are applied. In the absence of that schedule, tax credits must be applied in the following order:

(1) first, any credit under AS 43.55.024 (a);

(2) second, any credit under AS 43.55.024 (c);

(3) third, any credit under AS 43.55.025 ;

(4) fourth, any credit under AS 43.55.023 (i);

(5) fifth, any credit under AS 43.55.023 (a);

(6) sixth, any credit under AS 43.55.023 (b);

(7) seventh, any credit under AS 41.09.010 ;

(8) eighth, any credit under AS 38.05.180 (i);

(9) ninth, any credit under AS 43.55.023 (e).

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.023

AS 43.55.024

AS 43.55.025

AS 43.55.110

15 AAC 55.380. Subtraction of tax credits in calculation of installment payment of estimated tax for oil and gas produced before July 1, 2007

(a) For purposes only of the

(1) calculation required under AS 43.55.020 (a)(2)(A), as the provisions of that subparagraph read on June 30, 2007, the amount of the tax credits that are allowed by law to be applied against the tax levied by AS 43.55.011 (e), as the provisions of that subsection read on June 30, 2007, for a calendar year

(A) is calculated without regard to a minimum tax under AS 43.55.011 (f); and

(B) does not include any amount of a tax credit that the producer transfers to another person;

(2) calculations required under AS 43.55.020 (a)(1) - (3), as the provisions of those paragraphs read on June 30, 2007, the amount calculated under AS 43.55.020 (a)(2), as the provisions of that paragraph read on June 30, 2007, may be less than zero, but the sum of the amounts calculated under AS 43.55.020 (a)(2) and (3), as the provisions of those paragraphs read on June 30, 2007, may not be less than zero;

(3) installment payment required under AS 43.55.020 (a)(4), as the provisions of that paragraph read on June 30, 2007, a tax credit is not deductible in calculating the amount of the payment.

(b) The provision of AS 43.55.020 (a)(2)(A), as that subparagraph read on June 30, 2007, prescribing a limit of 1/12 of certain tax credits does not apply to a tax credit shown on a transferable tax credit certificate that has been issued under AS 43.55.023 (d) or a tax credit for which a production tax credit certificate has been issued under AS 43.55.025 (f). Subject to the provision of AS 43.55.020 (a)(1), as that paragraph read on June 30, 2007, that the amount of an installment payment may not be less than zero and subject to the 80 percent limitation provided under AS 43.55.023 (e), in calculating the amount described in AS 43.55.020 (a)(2) for a month, as the provisions of that paragraph read on June 30, 2007, a producer that owns a transferable tax credit certificate or production tax credit certificate may subtract any percentage, irrespective of whether it is equal to or greater than 1/12, of the credit that was not previously subtracted, to the extent that the credit is allowed by law to be applied against the tax levied by AS 43.55.011 (e) for the calendar year.

(c) If in calculating the amount of an installment payment for a month required under AS 43.55.020 (a)(1), as the provisions of that paragraph read on June 30, 2007, a producer is unable to subtract the full amount of tax credits described in AS 43.55.020 (a)(2)(A), as the provision of that subparagraph read on June 30, 2007, the unused amount of tax credits is not considered an overpayment, does not accrue interest, and except as provided under (b) of this section may not be carried forward to or used in calculating an installment payment for a future month. The amount of tax credits subtracted in calculating the amount of an installment payment does not affect the availability of tax credits to be applied as allowed by law against an annual tax liability under AS 43.55.011 in calculating the amount due under AS 43.55.020 (a)(5), as the provisions of that paragraph read on June 30, 2007.

(d) This section applies to oil and gas produced before July 1, 2007.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

15 AAC 55.381. Subtraction of tax credits in calculation of installment payment of estimated tax for oil and gas produced after June 30, 2007

(a) For purposes of the

(1) calculation required under AS 43.55.020 (a)(1), the amount of the tax credits that are allowed by law to be applied against the tax levied by AS 43.55.011 (e) for a calendar year does not include any amount of a tax credit that the producer transfers to another person;

(2) installment payment required under AS 43.55.020 (a)(3), a tax credit is not deductible in calculating the amount of the payment.

(b) The provision of AS 43.55.020 (a)(1) prescribing a limit of 1/12 of certain tax credits does not apply to a tax credit shown on a transferable tax credit certificate that has been issued under AS 43.55.023 (d) or a tax credit for which a production tax credit certificate has been issued under AS 43.55.025 (f). Subject to the provision of AS 43.55.020 (a)(1) that the amount of an installment payment may not be less than zero and subject to the 80 percent limitation provided under AS 43.55.023 (e), in calculating the amount of an installment payment under AS 43.55.020 (a)(1) for a month, a producer that owns a transferable tax credit certificate or production tax credit certificate may subtract any percentage, irrespective of whether it is equal to or greater than 1/12, of the credit that was not previously subtracted, to the extent that the credit is allowed by law to be applied against the tax levied by AS 43.55.011 (e) for the calendar year.

(c) If in calculating the amount of an installment payment for a month required under AS 43.55.020 (a)(1), a producer is unable to subtract the full amount of tax credits described in AS 43.55.020 (a)(1), the unused amount of tax credits is not considered an overpayment, does not accrue interest, and except as provided under (b) of this section may not be carried forward to or used in calculating an installment payment for a future month. The amount of tax credits subtracted in calculating the amount of an installment payment does not affect the availability of tax credits to be applied as allowed by law against an annual tax liability under AS 43.55.011 in calculating the amount due under AS 43.55.020 (a)(4).

(d) This section applies to oil and gas produced after June 30, 2007.

History: Eff. 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.110

Article 4
Levy of Tax

Section

15 AAC 55.410. Tax on production tax value of oil and gas

(a) The tax levied by AS 43.55.011 (e) is levied for a calendar year for all taxable oil and gas produced during all months of the calendar year.

(b) The comparison provided under AS 43.55.011 (e), as the provisions of that subsection read on June 30, 2007, between 22.5 percent of the production tax value of a producer's taxable oil and gas and the minimum tax determined under AS 43.55.011 (f), as the provisions of that subsection read on June 30, 2007, applies only to oil and gas produced before July 1, 2007, from leases or properties in the state north of 68 degrees North latitude. Except as otherwise provided under AS 43.55.011 (j) and (k), the tax levied by AS 43.55.011 (e), as the provisions of that subsection read on June 30, 2007, for the rest of the producer's taxable oil and gas produced before July 1, 2007, is equal to 22.5 percent of the production tax value of that oil and gas as calculated under AS 43.55.160 , as the provisions of that section read on June 30, 2007, irrespective of whether the minimum tax determined under AS 43.55.011 (f), as the provisions of that subsection read on June 30, 2007, is greater than 22.5 percent of the production tax value of the producer's taxable oil and gas produced from leases or properties in the state north of 68 degrees North latitude.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

15 AAC 55.420. Minimum tax for oil and gas produced before July 1, 2007

(a) For purposes of AS 43.55.011 (e), as the provisions of that subsection read on June 30, 2007, a producer's minimum tax for a calendar year determined under AS 43.55.011 (f), as the provisions of that subsection read on June 30, 2007, on oil and gas produced before July 1, 2007, from leases or properties in the state north of 68 degrees North latitude is the amount calculated by

(1) calculating the applicable percentage under AS 43.55.011 (f), as the provisions of that subsection read on June 30, 2007, of the gross value at the point of production of all oil and gas produced by the producer during the calendar year from leases or properties in the state north of 68 degrees North latitude, excluding only oil and gas the ownership or right to which is exempt from taxation; and

(2) subtracting, from the amount calculated under (1) of this subsection, the sum of

(A) the tax, if any, levied by AS 43.55.011 (g), as the provisions of that subsection read on June 30, 2007, for oil and gas produced by the producer during the calendar year from leases or properties in the state north of 68 degrees North latitude and taxable under AS 43.55.011 (g), as the provisions of that subsection read on June 30, 2007; and

(B) the tax, if any, levied by AS 43.55.011 (i) for oil and gas produced by the producer during the calendar year from leases or properties in the state north of 68 degrees North latitude and taxable under AS 43.55.011 (i).

(b) A producer's minimum tax calculated under AS 43.55.011 (f) and (a) of this section may not be less than zero.

(c) For purposes of AS 43.55.011 (f), the average price per barrel for ANS for sale on the United States West Coast during a calendar year is equal to the simple average of the average spot prices for ANS at the United States West Coast during all months of the calendar year as calculated under 15 AAC 55.171(m) .

(d) This section applies to oil and gas produced before July 1, 2007.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

15 AAC 55.421. Minimum tax for oil and gas produced after June 30, 2007

(a) For purposes of AS 43.55.011 (e), a producer's minimum tax for a calendar year determined under AS 43.55.011 (f) on oil and gas produced after June 30, 2007, from leases or properties in the state north of 68 degrees North latitude is the amount calculated by multiplying the applicable percentage under AS 43.55.011 (f) by the gross value at the point of production of all oil and gas produced by the producer during the calendar year from leases or properties in the state north of 68 degrees North latitude, excluding

(1) oil and gas the ownership or right to which is exempt from taxation;

(2) oil and gas for which tax is calculated under AS 43.55.011 (i); and

(3) gas subject to AS 43.55.011 (o).

(b) For purposes of AS 43.55.011 (f), the average price per barrel for ANS for sale on the United States West Coast during a calendar year is equal to the simple average of the average spot prices for ANS at the United States West Coast during all months of the calendar year as calculated under 15 AAC 55.171(m) .

(c) This section applies to oil and gas produced after June 30, 2007.

History: Eff. 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

15 AAC 55.430. Tax based on price index for oil and gas produced before July 1, 2007

(a) The amount of tax levied by AS 43.55.011 (g), as the provisions of that subsection read on June 30, 2007, for oil and gas produced before July 1, 2007, is calculated separately for each segment under 15 AAC 55.205(c) for each month in a calendar year. The amount of tax for a segment for a month is equal to the monthly production tax value for the segment under AS 43.55.160 (a)(2), as the provisions of that subsection read on June 30, 2007, and 15 AAC 55.205, multiplied by a tax rate that is equal to the product of .25 percent multiplied by the price index for the month determined under AS 43.55.011 (h), as the provisions of that subsection read on June 30, 2007. For purposes of the sum, over all months in a calendar year, of the amounts of tax calculated for each month under AS 43.55.011 (g), as the provisions of that subsection read on June 30, 2007, if the price index for a month determined under AS 43.55.011 (h), as the provisions of that subsection read on June 30, 2007, is zero, the amount of tax calculated for all segments for that month is zero.

(b) The price index determined under AS 43.55.011 (h), as the provisions of that subsection read on June 30, 2007, is calculated separately for each month in a calendar year. For purposes only of AS 43.55.011 (h), as the provisions of that subsection read on June 30, 2007, the total

(1) monthly production tax value of the taxable oil and gas produced by a producer during a month is the total gross value at the point of production of that taxable oil and gas produced from all leases or properties in the state, less 1/12 of the total adjusted lease expenditures incurred by the producer during the calendar year irrespective of the lease or property in the state from which the oil and gas, if any, to which the lease expenditures are applicable under 15 AAC 55.215 were produced;

(2) amount of the taxable oil and gas produced by a producer during a month is the total amount of oil and gas taxable under AS 43.55.011 (g), as the provisions of that subsection read on June 30, 2007, and produced by the producer during the month from all leases or properties in the state.

(c) For purposes of determining a price index under AS 43.55.011 (h), as the provisions of that subsection read on June 30, 2007, and a tax rate under (a) of this section, the automatic convention in the rounding command or function in commercially available software must be followed to round

(1) the price index to the nearest 1/10 of a cent; and

(2) the tax rate, expressed as a percentage, to three decimal places.

(d) This section applies to oil and gas produced before July 1, 2007.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

AS 43.55.160

15 AAC 55.431. Monthly tax amounts under AS 43.55.011 (e)(2) for oil and gas produced after June 30, 2007

(a) The amount of tax determined under AS 43.55.011 (g) for purposes of AS 43.55.011 (e)(2) is calculated separately for each segment under 15 AAC 55.206(c) for each month in a calendar year. The amount of tax for a segment for a month is equal to the monthly production tax value for the segment under AS 43.55.160 (a)(2) and 15 AAC 55.206, multiplied by the tax rate for the month calculated under AS 43.55.011 (g).

(b) For purposes of AS 43.55.011 (g), a producer's average monthly production tax value under AS 43.55.160 (a)(2) per BTU equivalent barrel of the taxable oil and gas is the BTU equivalent barrel-weighted arithmetic mean of the monthly production tax values per BTU equivalent barrel of all of the producer's segments.

(c) For purposes of determining a tax rate under AS 43.55.011 (g), the automatic convention in the rounding command or function in commercially available software must be followed to round

(1) the producer's average monthly production tax value per BTU equivalent barrel to the nearest 1/10 of a cent; and

(2) the tax rate, expressed as a percentage, to three decimal places.

(d) This section applies to oil and gas produced after June 30, 2007.

History: Eff. 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

AS 43.55.160

15 AAC 55.440. Tax limitations for Cook Inlet and for gas used in the state

(a) For purposes of AS 43.55.011 (j)(2),

(1) the average rate of tax that was imposed under AS 43.55 on taxable gas produced from all leases or properties in the Cook Inlet sedimentary basin for the 12-month period ending on March 31, 2006, was 4.947 percent; and

(2) the average prevailing value for gas delivered in the Cook Inlet area for the 12-month period ending March 31, 2006, as determined by the department under AS 43.55.020 (f), was $3.585 per Mcf.

(b) For purposes of AS 43.55.011 (k)(2), the average rate of tax that was imposed under AS 43.55 on taxable oil produced from all leases or properties in the Cook Inlet sedimentary basin for the 12-month period ending on March 31, 2006, was zero percent.

(c) Gas produced after March 31, 2006, from a lease or property in the Cook Inlet sedimentary basin that first commenced commercial production of gas before April 1, 2006, but had no production of taxable gas during the 12-month period ending on March 31, 2006, is subject to the provisions of AS 43.55.011 (j)(2). Oil produced after March 31, 2006, from a lease or property in the Cook Inlet sedimentary basin that first commenced commercial production of oil before April 1, 2006, but had no production of taxable oil during the 12-month period ending on March 31, 2006, is subject to the provisions of AS 43.55.011 (k)(2).

(d) For purposes of AS 43.35.011 (o), the amount of tax for each Mcf determined under AS 43.55.011 (j)(2) is $.177.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.020

AS 43.55.110

15 AAC 55.450. Tax for oil and gas the ownership or right to which constitutes a landowner's royalty interest

(a) The tax levied by AS 43.55.011 (i) for oil is calculated separately for oil produced from each lease or property and may not be less than zero.

(b) The tax levied by AS 43.55.011 (i) for gas is calculated separately for gas produced from each lease or property and may not be less than zero.

History: Eff. 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.110

Article 5
Payments and Reporting

Section

15 AAC 55.510. Installment payments of estimated tax for oil and gas produced before July 1, 2007

(a) If a limitation under AS 43.55.011 (j) or (k) on the tax levied by AS 43.55.011 (e) and (g), as the provisions of those subsections read on June 30, 2007, has the effect of reducing a producer's tax for a calendar year for oil or gas produced before July 1, 2007, from a lease or property in the Cook Inlet sedimentary basin below the amount of tax that would be levied in the absence of that limitation, the calculation of the amount of the producer's installment payment required by AS 43.55.020 (a)(1) - (3), as the provisions of those paragraphs read on June 30, 2007, for each month of the calendar year is modified in the manner set out in (b) - (d) of this section.

(b) The production tax value of oil and gas for which the producer's tax is reduced as described in (a) of this section is excluded from the calculations described in AS 43.55.020 (a)(2)(B) and (3), as the provisions of that subparagraph and paragraph read on June 30, 2007.

(c) For each lease or property for which the producer's tax for gas is reduced as described in (a) of this section, the following amount is added to the amount calculated for each month under AS 43.55.020 (a)(2)(B), as the provisions of that subparagraph read on June 30, 2007: the product obtained by carrying out the calculation set out in AS 43.55.011 (j)(1) or (2), as applicable, but substituting in AS 43.55.011 (j)(1)(A) or (2)(A), as applicable, the amount of taxable gas produced during the month for the amount of taxable gas produced during the calendar year.

(d) For each lease or property for which the producer's tax for oil is reduced as described in (a) of this section, the following amount is added to the amount calculated for each month under AS 43.55.020 (a)(2)(B), as the provisions of that subparagraph read on June 30, 2007: the product obtained by carrying out the calculation set out in AS 43.55.011 (k)(1) or (2), as applicable, but substituting in AS 43.55.011 (k)(1)(A) or (2)(A), as applicable, the amount of taxable oil produced during the month for the amount of taxable oil produced during the calendar year.

(e) This section applies to oil and gas produced before July 1, 2007.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.020

AS 43.55.110

15 AAC 55.511. Installment payments of estimated tax for oil and gas produced after June 30, 2007

(a) For purposes of the calculation described in AS 43.55.020 (a)(1)(A)(ii) for oil and gas produced after June 30, 2007, the gross value at the point of production of the oil and gas produced and the deductible adjusted lease expenditures are calculated only for oil and gas taxable under AS 43.55.011 (e) and not subject to AS 43.55.011 (f) or (o).

(b) For purposes of the calculation described in AS 43.55.020 (a)(1)(B)(ii) for oil and gas produced after June 30, 2007,

(1) the gross value at the point of production of the oil and gas produced is calculated only for oil and gas taxable under AS 43.55.011 (e), subject to AS 43.55.011 (f), and not subject to AS 43.55.011 (o);

(2) the applicable percentage of the gross value at the point of production is determined under AS 43.55.011 (f)(1) - (4) but substituting the phrase "the month for which the installment payment is calculated" for the phrase "calendar year for which the tax is due";

(3) the average price per barrel for Alaska North Slope crude oil for sale on the United States West Coast during a month is equal to the average spot price for ANS at the United States West Coast during the month as calculated under 15 AAC 55.171(m) .

(c) For purposes of the calculation described in AS 43.55.020 (a)(1)(B)(iii) for oil and gas produced after June 30, 2007, the gross value at the point of production of the oil and gas produced and the deductible adjusted lease expenditures are calculated only for oil and gas taxable under AS 43.55.011 (e), subject to AS 43.55.011 (f), and not subject to AS 43.55.011 (o).

(d) For purposes of the calculation described in AS 43.55.020 (a)(1)(C)(ii) for oil and gas produced after June 30, 2007, the gross value at the point of production of the oil or gas produced and the deductible adjusted lease expenditures are calculated only for oil and gas taxable under AS 43.55.011 (e) and subject to AS 43.55.011 (j), (k), or (o).

(e) For purposes of calculating the installment payment required under AS 43.55.020 (a)(3), the amount under

(1) AS 43.55.020 (a)(3)(A) is calculated separately for each lease or property and may not be less than zero;

(2) AS 43.55.020 (a)(3)(B) is calculated separately for each lease or property and may not be less than zero.

History: Eff. 10/21/2009, Register 192; am 4/30/2010, Register 194

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.020

AS 43.55.110

15 AAC 55.520. Monthly filings

(a) For each month for which a producer is required to make an installment payment of estimated tax under AS 43.55.020 (a)(1) or (3), a surcharge under AS 43.55.201 , or a surcharge under AS 43.55.300 , the producer or the person paying on behalf of the producer shall provide to the department with the payment a remittance advice identifying the producer, the amount and type of the payment, and the month and calendar year of production for which the payment is made. If a single payment combining amounts due under two or more of the provisions referenced in this subsection is made for a month, the remittance advice must state the respective amount paid under each provision. In the absence of the pertinent information required by this subsection, the department will treat a payment received as an installment payment of estimated tax due under AS 43.55.020 (a)(1) and (3) on the last day of the month before the month in which the payment is made.

(b) An operator of a lease or property in the state from which oil or gas is produced during a month shall submit to the department no later than the last day of the following month

(1) the production offtake schedule and the operator's supporting documentation for the month of production for the lease or property;

(2) the information described in 15 AAC 55.021(a) , if applicable; and

(3) a report of any unscheduled interruption of, or reduction in the rate of, oil or gas production during the month.

(c) A producer shall submit to the department no later than the last day of each month, a complete copy of each contract, agreement, and amendment to a contract or agreement that was entered into by the producer during the previous month and that concerns the sale, exchange, or transportation of oil or gas produced in the state, unless the contract, agreement, or amendment was previously provided to the department under this subsection. The producer shall also submit to the department a summary list of all contracts, agreements, and amendments to a contract or agreement to which the producer is a party and that concern the sale, exchange, or transportation of oil or gas produced in the state during the previous month. The list must include a notation as to when each contract was submitted to the department. On a form prescribed by the department, the producer shall identify the contract, agreement, or amendment to the contract or agreement that concerns each disposition of oil or gas reported on the form.

(d) No later than 60 days after the department sends a written request, a person subject to (b) or (c) of this section shall submit to the department any additional documents obtained by or generated by the person that concern a matter that is the subject of a submission required to be made to the department under (b) or (c) or this section.

(e) If a person subject to (b), (c), or (d) of this section fails to submit documents or information required under (b), (c), or (d) of this section, the department may request the documents or information from any producer of oil or gas from the lease or property in question. A producer to which the department makes a written request under this subsection shall submit the requested documents or information no later than 60 days after the request is sent.

(f) A producer or explorer that produces oil or gas during a month, incurs a lease expenditure during a month, incurs an expenditure during a month for which a tax credit may be claimed under AS 43.55.025 , or receives during a month a payment or credit that constitutes an adjustment to lease expenditures under AS 43.55.170 shall submit to the department no later than the last day of the following month a report of

(1) amounts and dispositions of oil and gas produced;

(2) destination values, calculated in accordance with 15 AAC 55.151(b) (1), of oil and gas produced;

(3) transportation costs and adjustments for oil and gas produced;

(4) lease expenditures incurred, separately setting out

(A) qualified capital expenditures and other lease expenditures;

(B) exploration, development, and production expenditures;

(C) expenditures for which a tax credit may be claimed under AS 43.55.025 and the anticipated amount of the tax credit;

(D) overhead allowance;

(E) property taxes;

(F) net profit share payments;

(G) exclusions under AS 43.55.165 (e)(18) and (19); and

(H) applicable lease expenditures under AS 43.55.165 (j) and (k);

(5) payments or credits received that constitute adjustments to lease expenditures under AS 43.55.170 ;

(6) tax credits subtracted in calculating the monthly installment payment of estimated tax;

(7) potential tax credits generated during the month but of which no portion is subtracted in calculating the monthly installment payment of estimated tax;

(8) tax credit certificates issued under AS 43.55.023 or 43.55.025 and transferred to another person; and

(9) tax payments, including conservation surcharges under AS 43.55.201 or 43.55.300, due for the month.

(g) Reports and other documents required to be submitted to the department under this section must be filed electronically in the applicable form prescribed by the department.

History: Eff. 5/3/2007, Register 182; am 5/17/2008, Register 186

Authority: AS 43.05.080

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

AS 43.55.165

AS 43.55.180

Article 6
General Provisions

Section

15 AAC 55.800. Retroactive application of regulations

(a) The following provisions apply retroactively to April 1, 2006, to oil and gas produced after March 31, 2006:

(1) 15 AAC 55.192;

(2) 15 AAC 55.205;

(3) 15 AAC 55.215;

(4) 15 AAC 55.223;

(5) 15 AAC 55.245, as amended effective December 4, 2010;

(6) 15 AAC 55.270, as amended effective December 4, 2010, except 15 AAC 55.270(a) 2)(C) and (e), which apply retroactively to July 1, 2007;

(7) 15 AAC 55.275;

(8) 15 AAC 55.280, as repealed and readopted effective December 4, 2010;

(9) 15 AAC 55.290 - 15 AAC 55.315;

(10) 15 AAC 55.330 - 15 AAC 55.340;

(11) 15 AAC 55.345 - 15 AAC 55.355;

(12) 15 AAC 55.370 - 15 AAC 55.380;

(13) 15 AAC 55.410;

(14) 15 AAC 55.420;

(15) 15 AAC 55.430;

(16) 15 AAC 55.440;

(17) 15 AAC 55.510;

(18) 15 AAC 55.810;

(19) 15 AAC 55.850;

(20 15 AAC 55.900(a) (21) - (26) and (b)(21) - (25).

(b) 15 AAC 55.830 applies retroactively to March 1, 2007.

(c) Except for purposes of calculating, under sec. 36(c)(1), ch. 2, TSSLA 2006 (Transitional Provisions), the amount of taxes that would have been levied on a producer by AS 43.55, as the provisions of that chapter read on March 31, 2006, the repeal of the following provisions applies retroactively to April 1, 2006, to oil and gas produced after March 31, 2006:

(1) 15 AAC 55.010;

(2) 15 AAC 55.011;

(3) 15 AAC 55.021(b) , (d), (e), (g), and (h);

(4) 15 AAC 55.027;

(5) 15 AAC 55.050;

(6) 15 AAC 55.052;

(7) 15 AAC 55.071;

(8) 15 AAC 55.090;

(9) 15 AAC 55.100;

(10) 15 AAC 55.115;

(11) 15 AAC 55.173(e) and (f);

(12) 15 AAC 55.175;

(13) 15 AAC 55.191(b) (6) and (7);

(14) 15 AAC 55.191(t) ;

(15) 15 AAC 55.200;

(16) 15 AAC 55.220;

(17) 15 AAC 55.225;

(18) 15 AAC 55.240;

(19) 15 AAC 55.900(a) (6);

(20) 15 AAC 55.900(a) (14);

(21) 15 AAC 55.900(a) (16);

(22) 15 AAC 55.900(b) (4) - (7).

(d) The repeal of 15 AAC 55.080 applies retroactively to March 1, 2007.

(e) Except for purposes of calculating, under sec. 36(c)(1), ch. 2, TSSLA 2006 (Transitional Provisions), the amount of taxes that would have been levied on a producer by AS 43.55, as the provisions of that chapter read on March 31, 2006, the changes to the following provisions, effective May 3, 2007, apply retroactively to April 1, 2006, to oil and gas produced after March 31, 2006:

(1) 15 AAC 55.151;

(2) 15 AAC 55.171(a) , (g), (h), and (k);

(3) 15 AAC 55.173(a) - (d);

(4) 15 AAC 55.191(b) (8);

(5) 15 AAC 55.195(g) and (i);

(6) 15 AAC 55.900(a) (7)(B) - (C), (9), and (11).

(f) The following provisions apply retroactively to July 1, 2007:

(1) 15 AAC 55.181;

(2) 15 AAC 55.193;

(3) 15 AAC 55.197;

(4) 15 AAC 55.206;

(5) 15 AAC 55.224;

(6) 15 AAC 55.341;

(7) 15 AAC 55.381;

(8) 15 AAC 55.421;

(9) 15 AAC 55.431;

(10) 15 AAC 55.511(a) - (d);

(11) 15 AAC 55.900(b) (26) and (27).

(g) The provisions of 15 AAC 55.805 apply retroactively to July 1, 2007, insofar as that section affects the determination of tax for periods after June 30, 2007, and otherwise apply retroactively to January 1, 2007.

(h) The repeal of 15 AAC 55.900(b) (20) applies retroactively to July 1, 2007.

(i) The provisions of 15 AAC 55.250 and 15 AAC 55.260, as amended effective December 4, 2010, apply retroactively to April 1, 2006, with respect to costs incurred before July 1, 2007, and otherwise apply retroactively to July 1, 2007.

(j) The changes to the following provisions, effective April 30, 2010, apply retroactively to July 1, 2007:

(1) 15 AAC 55.151(b) ;

(2) 15 AAC 55.151(c) (3);

(3) 15 AAC 55.192;

(4) 15 AAC 55.195(a) ;

(5) 15 AAC 55.195(c) (1).

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192; am 2/27/2010, Register 193; am 4/30/2010, Register 194; am 12/4/2010, Register 196

Authority: AS 43.05.080

AS 43.55.110

Sec. 37, ch. 2,

TSSLA 2006

Sec. 72, ch. 1,

SSSLA 2007

15 AAC 55.805. Rules for 2007 mid-year statutory changes

(a) Except as provided by AS 43.55.011 (f), (j), (k), and (o) and by (e) of this section, the tax levied on a producer for calendar year 2007 by AS 43.55.011 , other than the tax levied by AS 43.55.011 (i), is the sum of the tax calculated under (b) of this section for the period after December 31, 2006, and before July 1, 2007, and the tax calculated under (c) of this section for the period after June 30, 2007, and before January 1, 2008.

(b) For purposes of (a) of this section, the tax for the period after December 31, 2006, and before July 1, 2007, is the sum of

(1) 22.5 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160 (a)(1), as the provisions of that paragraph read on June 30, 2007, but substituting in that calculation the gross value at the point of production of the oil or gas, as applicable, produced during the first six months of the calendar year in place of the entire calendar year and the lease expenditures, as adjusted, for the first six months of the calendar year in place of the entire calendar year; and

(2) the sum, over the first six months of the calendar year, of the amounts calculated for each month under AS 43.55.011 (g), as the provisions of that subsection read on June 30, 2007.

(c) For purposes of (a) of this section, the tax for the period after June 30, 2007, and before January 1, 2008, is the sum of

(1) 25 percent of the production tax value of the taxable oil and gas as calculated under AS 43.55.160 (a)(1) as amended by sec. 54, ch. 1, SSSLA 2007, but substituting in that calculation the gross value at the point of production of the oil or gas, as applicable, produced during the last six months of the calendar year in place of the entire calendar year and the lease expenditures, as adjusted, for the last six months of the calendar year in place of the entire calendar year; and

(2) the sum, over the last six months of the calendar year, of the tax amounts determined for each month under AS 43.55.011 (g) as repealed and reenacted by sec. 17, ch. 1, SSSLA 2007.

(d) For purposes of

(1) paragraphs (b)(1) and (c)(1) of this section, in the case of a unit subject to AS 43.55.165 (j) and (k), the lease expenditures, other than qualified capital expenditures, for each six-month period of 2007 are equal to one-half of the lease expenditures, other than qualified capital expenditures, determined under AS 43.55.165 (j) and (k) for calendar year 2007;

(2) paragraphs (b)(2) and (c)(2) of this section, monthly production tax values are calculated using 1/6 of the lease expenditures for the respective six-month period of 2007 and an appropriate monthly share, as determined using an acceptable method under 15 AAC 55.192, of the producer's costs of transportation for the respective six-month period or, at the producer's option, of the producer's costs of transportation for the entire calendar year; however, the producer has the option of using a monthly share of the producer's costs of transportation for the entire calendar year only if actual costs, rather than reasonable costs, of transportation are deductible for the last six months of 2007 under AS 43.55.150 (a) and (b).

(e) The maximum amount of tax provided by AS 43.55.011 (j) and (k) is determined separately for the first six months and the last six months of 2007, based on the amount of taxable gas or oil, respectively, produced from the lease or property during the applicable six-month period rather than during the entire calendar year. The maximum amount of tax provided by AS 43.55.011 (o) is determined only for the last six months of 2007, based on the amount of taxable gas produced from the lease or property during the last six months of 2007. The minimum amount of tax provided by AS 43.55.011 (f) is determined separately for the first six months and the last six months of 2007, but with reference to the average price per barrel for ANS for sale on the United States West Coast for the entire calendar year.

(f) The limitation in AS 43.55.023 (a)(1) that not more than half of a tax credit under AS 43.55.023 (a) may be applied for a single calendar year applies only to tax credits for qualified capital expenditures that are incurred after June 30, 2007.

(g) A tax credit under AS 43.55.023 (b) that is applied against a tax levied for calendar year 2007 is 20 percent of the amount of the carried-forward annual loss.

(h) For purposes of determining tax credits under AS 43.55.023 (b) based on lease expenditures incurred during 2007, a carried-forward annual loss for the

(1) first six months of 2007 is the amount of adjusted lease expenditures that was not deductible in calculating production tax values under (b)(1) of this section, and the tax credit rate applicable to the carried-forward annual loss is 20 percent;

(2) last six months of 2007 is the amount of adjusted lease expenditures that was not deductible in calculating production tax values under (c)(1) of this section, and the tax credit rate applicable to the carried-forward annual loss is 25 percent.

(i) The provision of AS 43.55.023 (d) for issuance of two transferable tax credit certificates and postponement of use of the credit shown on the second of the two certificates applies only to tax credits based on expenditures incurred after June 30, 2007, and for which a transferable tax credit certificate had not been issued before December 20, 2007.

(j) For purposes of calculating the gross value at the point of production of oil or gas produced during the last six months of 2007, the lower of actual costs of transportation or reasonable costs of transportation is determined under AS 43.55.150 (b) for the six-month period after June 30, 2007, and before January 1, 2008.

(k) The provisions of 15 AAC 55.223 and 15 AAC 55.224 are applied respectively for the first six months and the last six months of 2007, using production tax values, adjusted lease expenditures, and determinations of the maximum amount of tax provided by AS 43.55.011 (j), (k), and (o) for the applicable six-month period instead of for the calendar year.

(*l*) For calendar year 2007, the exclusion from lease expenditures provided by AS 43.55.165 (e)(18) is determined separately for the first six months and the last six months of the calendar year, based on the expenditures incurred during the respective six-month period and the total taxable production during the respective six-month period.

History: Eff. 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.023

AS 43.55.110

AS 43.55.150

AS 43.55.160

AS 43.55.165

Sec. 73, ch. 1,

SSSLA 2007

Sec. 74, ch. 1,

SSSLA 2007

15 AAC 55.810. Heating value of gas

(a) Except as provided in (c) of this section, the heating value of gas is determined by

(1) calculating the total or gross BTUs produced

(A) by the combustion, at constant pressure, of the amount of the gas that would occupy a volume of one cubic foot of space at a temperature of 60 degrees Fahrenheit, when the gas is

(i) saturated with water vapor and under a pressure equivalent to that of 14.73 pounds per square inch absolute; and

(ii) under standard gravitational force with air of the same temperature and pressure as the gas; and

(B) when the products of combustion are cooled to the initial temperature of the gas and air and when the water formed by combustion is condensed to the liquid state; and

(2) adjusting the calculation under (1) of this subsection for the actual water content of the gas.

(b) The heating value of gas produced from each lease or property must be sampled and the heating value determined under (a) of this section at least once per calendar year. The most recent determination of heating value must be applied to gas produced from the lease or property on or after the date the determination is made. If the first determination of heating value in compliance with (a) of this section is made after March 31, 2007, that determination must also be applied to gas that is produced from the lease or property after March 31, 2007, but before the date that determination is made.

(c) For gas produced before April 1, 2007, if the heating value is not determined under (a) - (b) of this section, the department will prescribe a reasonable method for estimating the heating value, based on the known heating value of gas produced more recently from the same reservoir or produced from a similar reservoir, an average heating value for gas produced from a type of reservoir or from an area of the state, or a standard industry practice.

History: Eff. 5/3/2007, Register 182

Authority: AS 43.05.080

AS 43.55.110

AS 43.55.900

15 AAC 55.820. Retroactive changes

Repealed.

History: Eff. 5/3/2007, Register 182; repealed 10/21/2009, Register 192

Editor's note: The subject matter of 15 AAC 55.820 was formerly located at 15 AAC 55.200. The history note for 15 AAC 55.820 does not reflect the history of the earlier section.

For subject matter addressed in former 15 AAC 55.820, see AS 43.55.075 .

15 AAC 55.830. Interest

(a) Interest on an underpayment of tax, including an underpayment of an installment payment of estimated tax, is calculated for the time beginning with and including the day after the tax is due, and to and including the day the unpaid amount due is paid.

(b) Interest with respect to an underpayment or overpayment of an installment payment of estimated tax under AS 43.55.020 (g) or (h) is subject to the following requirements:

(1) except as otherwise provided in (2)(A) of this subsection, and for purposes only of determining the applicable rate of interest to be applied during a month based on the size of an underpayment or overpayment of tax under 26 U.S.C. 6621 (Internal Revenue Code), as amended,

(A) the size of that underpayment or overpayment of tax is considered to be equal to the total net outstanding amount of underpayments or overpayments including outstanding accrued interest, as of the end of

(i) the last day of the previous month; or

(ii) if the last day of the previous month is a Saturday, Sunday, or legal holiday as described in 15 AAC 05.310(h) , the next succeeding day that is not a Saturday, Sunday, or legal holiday;

(B) the higher interest rate provided under 26 U.S.C. 6621 (Internal Revenue Code), as amended, for a large corporate underpayment applies to the entire amount of an underpayment of tax if the amount would constitute a large corporate payment under that section; and

(C) the lower interest rate provided under 26 U.S.C. 6621 (Internal Revenue Code), as amended, to the extent that an overpayment exceeds $10,000, applies only to the portion of the amount of overpaid tax that exceeds $10,000;

(2) if a producer makes a payment on a day other than the last day of a month,

(A) the payment will be applied to any then outstanding net underpayment to the extent of that underpayment; interest ceases to accrue, as provided under (a) of this section, on the amount of the underpayment to which the payment is applied; the applicable rate of interest provided under 26 U.S.C. 6621 (Internal Revenue Code), as amended, during the rest of the month on any remaining balance of the net underpayment is determined by the size of that remaining balance, if any;

(B) the payment is not considered an overpayment or an increase in a producer's net outstanding amount of overpayments, if any, until the last day of the month;

(3) the earliest day that interest may begin to accrue on either an underpayment or overpayment with respect to the production of oil or gas during a calendar year is March 1 of that calendar year.

History: Eff. 5/3/2007, Register 182

Authority: AS 43.05.080

AS 43.05.225

AS 43.55.020

AS 43.55.060

AS 43.55.110

15 AAC 55.840. Penalties

(a) The department will not assess a civil penalty under AS 43.05.220 (a) or (b) for an underpayment of an installment payment of estimated tax required to be paid before February 1, 2011, under AS 43.55.020 (a)(1) or (4), as the provisions of those paragraphs read on June 30, 2007, or under AS 43.55.020 (a)(1) or (3), in effect on December 20, 2007, except in cases of intentional disregard of law or regulation. However, this section does not apply to a taxpayer's failure to pay a remaining unpaid amount of a required installment payment after March 31 of the year following the calendar year of production.

(b) If, 30 days after a report required to be filed under AS 43.55.030 is due, the department has not notified the person required to file the report that the person has failed to comply with the applicable requirement of AS 43.55.030 , the department will not assess, for failure to file the report, a penalty under AS 43.55.030 (d) that begins earlier than a date specified in a written notice to the person, except in case of the person's fraud or willful concealment. In that notice, the department will specify a date that is at least 10 days after the date of the department's delivery of the notice or, if the notice is mailed, at least 13 days after the date of mailing. Nothing in this subsection affects the person's obligation to file a complete and accurate report.

(c) If a person fails to file a report, statement, or other document required to be filed under AS 43.55.040 , the department will provide written notice of the failure to the person and will specify in the notice a date beginning on which the person will be liable for a penalty under AS 43.55.040 (7) if the person does not remedy the failure before that date. The department will specify a date that is at least 10 days after the date of the department's delivery of the notice or, if the notice is mailed, at least 13 days after the date of mailing. If, 30 days after the date specified, the department has not assessed a penalty or otherwise notified the person in writing that the person has failed to remedy the failure before the date specified, the department will not assess a penalty under AS 43.55.040 (7) for the failure, except in case of the person's fraud or willful concealment. Nothing in this subsection limits the department's right to require the additional or more complete and accurate filing of a report, statement, or other document.

(d) In determining the amount of a penalty under AS 43.55.030 (d) or 43.55.040(7), the department will consider the

(1) extent to which the person's failure to file was a willful or knowing act or omission or occurred despite a good faith attempt to comply;

(2) importance of the required information and of its timeliness to the department in the performance of its duties and functions;

(3) benefits, if any, derived by the person from failing to file;

(4) history of compliance or noncompliance by the person with AS 43.55 and this chapter;

(5) need to deter future noncompliance by the person and by others; and

(6) effort made by the person to correct the noncompliance and to ensure future compliance.

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.05.220

AS 43.55.020

AS 43.55.030

AS 43.55.040

AS 43.55.110

15 AAC 55.850. Calculation of average daily production

(a) For purposes of AS 43.55.024 (c) and 43.55.028(e)(6), a producer's average daily production of oil and gas during a calendar year is calculated by dividing the total amount of oil and gas, in BTU equivalent barrels, produced by the producer from all leases or properties in the state during the calendar year and taxable under AS 43.55.011 (e), by the total number of days in the calendar year. However, if a producer

(1) did not have commercial production of oil or gas from a lease or property in the state before January 2 of the calendar year, the number of days counted as the denominator in that calculation does not include days in the calendar year before the producer commenced commercial production;

(2) ceases all commercial production of oil and gas from leases or properties in the state on or before December 31 of the calendar year, the number of days counted as the denominator in that calculation does not include days in the calendar year after and including the date the producer ceases commercial production.

(b) As used in AS 43.55.028 (e)(6) and (a) of this section, "average daily production of oil and gas" has the same meaning as "average amount of oil and gas produced a day" as used in AS 43.55.024 (c).

History: Eff. 5/3/2007, Register 182; am 10/21/2009, Register 192

Authority: AS 43.05.080

AS 43.55.024

AS 43.55.028

AS 43.55.110

15 AAC 55.860. Unitary rounding

Unless otherwise specified, units must be rounded as follows:

(1) dollar amounts to the nearest dollar;

(2) barrel amounts to the nearest barrel;

(3) Mcf to the nearest Mcf;

(4) dollar per barrel amounts or dollars per Mcf amounts to the nearest 1/10 of a cent.

History: Eff. 5/3/2007, Register 182

Authority: AS 43.05.080

AS 43.55.110

15 AAC 55.900. Definitions

(a) Unless the context otherwise requires, as used in this chapter

(1) "department" means the Department of Revenue;

(2) "FASB" means the Financial Accounting Standards Board;

(3) "FASB-13" means FASB's Statement of Financial Accounting Standards No. 13, "Accounting for Leases" (November 1976), as amended or interpreted by FASB's Statement

of Financial Accounting Standards No. 17, "Accounting for Leases - Initial Direct Costs" (November 1977); FASB's Statement of Financial Accounting Standards No. 22, "Changes in the Provisions of Lease Agreements Resulting from Refundings of Tax-Exempt Debt" (June 1978); FASB's Statement of Financial Accounting Standards No. 23, "Inception of the Lease" (August 1978); FASB Interpretation No. 19, "Lessee Guarantee of the Residual Value of Leased Property" (October 1977); and FASB Interpretation No. 21, "Accounting for Leases in a Business Combination" (April 1978);

(4) "LNG transportation facility" means one or more of the following:

(A) the LNG liquefaction plant;

(B) gathering lines to the liquefaction plant;

(C) The LNG regasification plant;

(D) loading and unloading facilities for LNG tankers;

(E) LNG tankers;

(5) "pipeline facility" means all facilities incident to the pipeline transportation of oil or gas downstream from the point of production;

(6) repealed 5/3/2007;

(7) "sales delivery point" means

(A) for a producer's oil or gas sold in a bona fide, arm's-length sale to a third party, the point of delivery specified under the terms of the contract or agreement for that sale, except as otherwise provided by 15 AAC 55.151(g) , or 15 AAC 55.191(i) ;

(B) for a producer's oil to which (A) of this paragraph does not apply, the point where prevailing value is calculated under 15 AAC 55.171; and

(C) for a producer's gas to which (A) of this paragraph does not apply, the point where prevailing value is calculated under 15 AAC 55.173;

(8) "same regional market" means

(A) with respect to an oil that a producer refines or ultimately disposes of in the state, the Alaskan market;

(B) with respect to a producer's oil delivered to the United States West Coast (including Hawaii), the West Coast market or, if appropriate, the submarkets on the West Coast (i.e., Puget Sound, San Francisco Bay, the Long Beach and Los Angeles area, and Hawaii);

(C) with respect to a producer's oil delivered to the United States Gulf Coast, the Gulf Coast market;

(D) with respect to a producer's oil delivered to the United States East Coast, the East Coast market;

(E) with respect to a producer's oil delivered to Puerto Rico or the United States Virgin Islands, the Puerto Rico and United States Virgin Islands market;

(F) with respect to a producer's oil delivered to the United States Midcontinent region, the Midcontinent market;

(G) with respect to a producer's gas marketed in the state, the Alaskan market or portion of it served by gas from the same field or area as the producer's gas;

(H) with respect to a producer's gas delivered by pipeline and marketed in Canada or the Lower 48, the Canadian market or the Lower 48 market, as applicable, or, if appropriate, any submarkets in either Canada or the Lower 48;

(I) with respect to a producer's oil marketed in a foreign country, the market in that foreign country;

(J) with respect to a producer's gas delivered by an LNG transportation facility and marketed in a foreign country, the market in that foreign country;

(K) with respect to a producer's gas delivered by LNG transportation facility and marketed in the United States outside of the state, the West Coast market for LNG or the Hawaii market for LNG, as appropriate;

(9) "ANS" means oil produced in the Alaska North Slope area;

(10) "crude" means oil or unrefined liquid petroleum consisting principally of oil;

(11) "exchange"

(A) means a disposition of oil by a producer to a third party in which all or a portion of the full consideration received is oil or other non-cash consideration; and

(B) includes a related buy-sell agreement, tied sale, ratio exchange, or other arrangement where the producer's disposition of the oil to a third party is conditioned on the producer's purchase or receipt of oil or other non-cash consideration from that third party;

(12) "GNP deflator" means the gross national product deflator, as calculated quarterly by the Bureau of Economic Analysis, Economics and Statistics Administration, United States Department of Commerce;

(13) "LNG" means liquified natural gas;

(14) repealed 5/3/2007;

(15) "quality bank differential" means the difference per barrel between the value of a specified ANS stream that is commingled with one or more other streams at a pipeline connection and the value of the commingled pipeline stream, sometimes known as the reference stream, immediately downstream from that pipeline connection, as that difference in value is calculated by the person administering the pipeline quality bank for that pipeline connection;

(16) repealed 5/3/2007;

(17) "TAPS" means Trans Alaska Pipeline System;

(18) "consolidated business" means a corporation or group of corporations having more than 50 percent common ownership, direct or indirect, or a group of corporations in which common control exists, either direct or indirect, as evidenced by an arrangement, contract, or agreement;

(19) "in service" means

(A) engaged in transporting oil or gas produced in the state;

(B) returning to the state from a voyage that transported oil or gas produced in the state; or

(C) engaged in the ordinary and necessary operations incurred to transport oil or gas produced in the state;

(20) "field topping plant" means a facility into which a portion of a stream of hydrocarbon liquids is diverted and run, where distillation techniques are used to separate and remove certain liquid hydrocarbon fractions from the diverted liquids, and from which the remaining fractions of those hydrocarbon liquids are returned and blended back into the stream of undiverted hydrocarbon liquids at a point upstream of the point that constitutes the point of production for the undiverted liquids;

(21) "Mcf" means 1,000 cubic feet of gas;

(22) "qualified capital expenditure" has the meaning given in AS 43.55.023 (k);

(23) "oil or gas development operations" means the physical operations conducted in the field to

(A) drill and complete wells to produce oil or gas or to support oil or gas production, including installation of a drill pad or structure; or

(B) install oil or gas production equipment or facilities;

(24) "oil or gas exploration operations" means the physical operations conducted in the field to

(A) drill and obtain subsurface information from an exploration well, including installation of a drill pad or structure; or

(B) explore for oil or gas using geological or geophysical exploration techniques;

(25) repealed 12/4/2010.

(26) "oil or gas production operations"

(A) means the physical operations conducted in the field to

(i) lift oil or gas to the surface;

(ii) gather, separate, treat, and store on the surface well fluids upstream of the point of production; in this sub-subparagraph, "treat" does not include performing gas treatment as defined in AS 43.55.900 ;

(iii) perform gas processing upstream of the point of production;

(iv) meter oil or gas upstream of the point of production; and

(v) inject fluids in the reservoir from which the oil or gas is being produced, for reservoir pressure maintenance, repressuring, or enhanced recovery purposes;

(B) does not include compression of gas for the purpose of gas treatment as defined in AS 43.55.900 or of transporting gas to a market;

(27) "destination market" means a location or area where gas produced from leases or properties in the state, or any one of its components, is or can be physically bought, sold, transported, processed, or, in the case of LNG, regasified in the market;

(28) "downstream gas plant" means a facility that extracts and recovers liquid hydrocarbons from gas by gas processing downstream of the point of production of the gas;

(29) "downstream gas processing" means gas processing that occurs in a downstream gas plant;

(30) "downstream gas processing cost allowance" means an allowance for the cost of downstream gas processing determined by the department under 15 AAC 55.173(o) ;

(31) "FERC" means Federal Energy Regulatory Commission;

(32) "first destination market with reasonable liquidity" means a destination market that the department has determined meets the criteria established in 15 AAC 55.173(n) ;

(33) "gas plant products"

(A) means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, that can be derived by downstream gas processing of gas;

(B) includes

(i) propane;

(ii) butane;

(iii) isobutane;

(iv) pentane;

(v) ethane;

(vi) any NGL mix; in this sub-subparagraph, "NGL mix" means a mixture containing two or more NGLs;

(vii) condensate;

(viii) carbon dioxide or other non-hydrocarbon gases;

(C) does not include residue gas;

(34) "gas processing" has the meaning given in AS 43.55.900 ;

(35) "gas treatment" has the meaning given in AS 43.55.900 ;

(36) "gas treatment plant" means a facility that performs gas treatment;

(37) "Lower 48" means the 48 contiguous states and the District of Columbia;

(38) "MMBTU" means one million British thermal units;

(39) "NGL" means a liquid hydrocarbon that is extracted and recovered from gas by downstream gas processing;

(40) "producer" has the meaning given in AS 43.55.900 ;

(41) "regasification cost allowance" means an allowance for the cost of regasification of LNG delivered outside the state determined by the department in 15 AAC 55.173(o) ;

(42) "residue gas" means hydrocarbon gas that consists principally of methane after extraction of liquid hydrocarbons in a downstream gas plant.

(b) Unless the context otherwise requires, as used in this chapter and in AS 43.55,

(1) "area" means a geographic region or geologic province, including the Cook Inlet basin or the North Slope of the state;

(2) "field" means that part of an area underlain by one or more overlapping, contiguous, or superimposed pools, including Prudhoe Bay field or Middle Ground Shoal field in the state;

(3) repealed 4/30/2010;

(4) repealed 5/3/2007;

(5) repealed 5/3/2007;

(6) repealed 5/3/2007;

(7) repealed 5/3/2007;

(8) "abandoned" has the meaning given in 20 AAC 25.990;

(9) "bottom hole" has the meaning given the term "bottom-hole location" in 20 AAC 25.990;

(10) "completion date" means, for

(A) an exploration well, the earliest of the dates drilling ceased on the well site, the well was abandoned, or the well was suspended; and

(B) a preexisting well, the date the well was completed and equipped for producing fluids;

(11) "exploration unit" means a unit that

(A) contains state land and is under a plan of exploration; or

(B) does not contain state land and from which commercial production has not commenced;

(12) "exploration well" means a well drilled to discover or to delineate a pool or to gain structural or stratigraphic information to aid in exploring for oil and gas;

(13) "explorer" has the meaning given in AS 43.55.025 ; "explorer" does not include a drilling contractor, operator, or other person that does not hold an interest in the exploration well or seismic or geophysical work;

(14) "plan of exploration" means a plan submitted in accordance with 11 AAC 83.341;

(15) "plan of development" means a plan submitted in accordance with 11 AAC 83.343;

(16) "production unit" means a unit that

(A) contains state land and is under a plan of development; or

(B) does not contain state land and from which commercial production has commenced;

(17) "new oil or gas reserves" means previously undiscovered oil or gas reserves;

(18) "reserves" means unproduced but recoverable oil or gas in place in a formation;

(19) "suspended" has the meaning given in 20 AAC 25.990;

(20) repealed 10/21/2009;

(21) "commercial production" means production for purposes of sale or other beneficial use of oil or gas other than use associated with the exploration and development of the field in which the lease or property lies, except if the sale or beneficial use is incidental to the testing of an unproved well or unproved completion interval;

(22) "taxable under AS 43.55.011 (e)," when used in reference to oil or gas or both, means produced from a lease or property in the state but excluding any oil and gas the ownership or right to which is exempt from taxation or constitutes a landowner's royalty interest;

(23) "taxable under AS 43.55.011 (g)" has the meaning given "taxable under AS 43.55.011 (e)" in this subsection;

(24) "taxable under AS 43.55.011 (i)," when used in reference to oil or gas or both, means produced from a lease or property in the state the ownership or right to which constitutes a landowner's royalty interest, but excluding oil and gas the ownership or right to which is exempt from taxation;

(25) "other land" means, with respect to costs of exploration, land the right to explore for oil or gas deposits within which, or the right to drill a stratigraphic test well on which, has been granted by license or permit by the property owner to the producer or explorer that incurs, or on behalf of whom is incurred, the costs of that exploration;

(26) "affiliated" means, with respect to two or more persons, occupying a relationship in which one person controls another, is controlled by another, or is under common control with another, and includes the relationship between a person and a division of the person that operates as a functional unit;

(27) "control" has the meaning given in AS 43.90.900 .

(c) As used in AS 43.55, "agreement for unitization or pooling" means an agreement under which two or more persons owning working interests in a mineral interest in oil or gas or both agree to have the interests operated on a unified basis and further agree to share in production on a stipulated percentage or fractional basis regardless of the interest or interests from which the oil or gas is actually recovered and produced.

(d) As used in the definition of "producer" in AS 43.55.900 , "owner" includes

(1) a proprietorship;

(2) a partnership;

(3) a joint venture;

(4) a limited liability company;

(5) a corporation; and

(6) any entity that is affiliated with the owner.

History: Eff. 1/1/95, Register 132; am 1/1/2000, Register 152; am 1/1/2002, Register 160; am 1/1/2003, Register 164; am 1/1/2004, Register 168; am 5/3/2007, Register 182; am 10/21/2009, Register 192; am 2/27/2010, Register 193; am 4/30/2010, Register 194; am 12/4/2010, Register 196

Authority: AS 43.05.080

AS 43.55.011

AS 43.55.020

AS 43.55.023

AS 43.55.024

AS 43.55.025

AS 43.55.110

AS 43.55.150

AS 43.55.160

AS 43.55.165

AS 43.55.170

AS 43.55.900

Editor's note: Definitions for this chapter were formerly in 15 AAC 55.210.

15 AAC 55.9660. Number of oil wells

Repealed 7/1/77.

15 AAC 55.9670. Daily per well oil production

Repealed 7/1/77.

15 AAC 55.9690. Sales production ratio

Repealed 3/7/74.

15 AAC 55.9694. Tax rate changes based on wholesale price index

Repealed 7/1/77.

15 AAC 55.9699. Point of valuation of oil

Repealed 1/6/80.

15 AAC 55.9700. Definitions

Repealed 1/6/80.